PORTLAND GENERAL ELECTRIC CO /OR/
Form 10-Q
August 05, 2010
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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, 2010

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: 1-5532-99

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 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 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 30, 2010 is 75,294,987 shares.

PORTLAND GENERAL ELECTRIC COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2010

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DEFINITIONS

The following abbreviations and acronyms are used throughout this document:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
BART	Best Available Retrofit Technology
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal plant
BPA	Bonneville Power Administration
CERS	California Energy Resources Scheduling
Colstrip	Colstrip Units 3 and 4 coal plant
DEQ	Oregon Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage System
LLC	Limited Liability Company
Moody s	Moody s Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OEQC	Oregon Environmental Quality Commission
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
S&P	Standard & Poor s Ratings Services
SB 408	Oregon Senate Bill 408 (Oregon Revised Statutes 757.268)
SEC	Securities and Exchange Commission
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
VIE	Variable Interest Entity

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Dollars in millions, except per share amounts)

(Unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenues, net	$ 415	$ 389	$ 864	$ 874
Operating expenses:				
Purchased power and fuel	186	184	410	439
Production and distribution	46	43	85	85
Administrative and other	48	46	93	91
Depreciation and amortization	57	50	114	107
Taxes other than income taxes	21	21	44	44
Total operating expenses	358	344	746	766
Income from operations	57	45	118	108
Other income (expense):				
Allowance for equity funds used during construction	4	6	8	8
Miscellaneous income (expense), net	(3)	4	(2)	1
Other income, net	1	10	6	9
Interest expense	26	26	55	51
Income before income taxes	32	29	69	66
Income taxes	8	3	18	16
Net income	**24**	**26**	**51**	**50**
Less: net income (loss) attributable to noncontrolling interests	0	2	0	(5)
Net income attributable to Portland General Electric Company	**$ 24**	**$ 24**	**$ 51**	**$ 55**
Weighted-average shares outstanding (in thousands):				
Basic	75,276	75,131	75,253	70,352
Diluted	75,290	75,235	75,268	70,447
Earnings per share:				
Basic	$ 0.32	$ 0.31	$ 0.68	$ 0.77

Diluted	$ 0.32	$ 0.31	$ 0.68	$ 0.77
Dividends declared per common share	$ 0.260	$ 0.255	$ 0.515	$ 0.500

See accompanying notes to condensed consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)

(Unaudited)

	June 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 63	$ 31
Accounts receivable, net	128	159
Unbilled revenues	67	95
Inventories	62	58
Margin deposits	77	56
Regulatory assets - current	183	197
Current deferred income taxes	59	0
Other current assets	46	94
Total current assets	**685**	**690**
Electric utility plant, net	4,052	3,858
Regulatory assets - noncurrent	524	465
Non-qualified benefit plan trust	42	47
Nuclear decommissioning trust	33	50
Other noncurrent assets	68	62
Total assets	**$ 5,404**	**$ 5,172**

See accompanying notes to condensed consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS, continued

(Dollars in millions)

(Unaudited)

	June 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 152	$ 187
Liabilities from price risk management activities - current	172	128
Current portion of long-term debt	0	186
Regulatory liabilities - current	18	27
Other current liabilities	82	92
Total current liabilities	**424**	**620**
Long-term debt, net of current portion	1,808	1,558
Regulatory liabilities - noncurrent	665	654
Deferred income taxes	447	356
Liabilities from price risk management activities - noncurrent	183	127
Unfunded status of pension and postretirement plans	145	143
Non-qualified benefit plan liabilities	97	96
Other noncurrent liabilities	78	75
Total liabilities	**3,847**	**3,629**
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, 2010 and December 31, 2009	0	0
Common stock, no par value, 160,000,000 shares authorized; 75,294,987 and 75,210,580 shares issued and outstanding as of June 30, 2010 and December 31, 2009, respectively	830	829
Accumulated other comprehensive loss	(5)	(6)
Retained earnings	731	719
Total Portland General Electric Company shareholders equity	1,556	1,542
Noncontrolling interests equity	1	1
Total equity	**1,557**	**1,543**
Total liabilities and equity	**$ 5,404**	**$ 5,172**

See accompanying notes to condensed consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

(Unaudited)

	Six Months Ended June 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 51	$ 50
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	114	107
Increase in net liabilities from price risk management activities	95	6
Regulatory deferral - price risk management activities	(95)	(6)
Regulatory deferral of settled derivative instruments	27	2
Deferred income taxes	18	8
Allowance for equity funds used during construction	(8)	(8)
Decoupling mechanism deferrals, net	(8)	1
Senate Bill 408 deferrals, net	(7)	(1)
Power cost deferrals, net	(1)	(9)
Other non-cash income and expenses, net	26	12
Changes in working capital:		
Decrease in receivables	59	51
(Increase) decrease in margin deposits	(21)	62
Income tax refund received	53	0
Decrease in payables	(37)	(56)
Other working capital items, net	(9)	1
Other, net	(11)	0
Net cash provided by operating activities	**246**	**220**
Cash flows from investing activities:		
Capital expenditures	(264)	(395)
Distribution from Nuclear decommissioning trust	19	0
Sales of Nuclear decommissioning trust securities	18	17
Purchases of Nuclear decommissioning trust securities	(17)	(17)
Other, net	(1)	(1)
Net cash used in investing activities	**(245)**	**(396)**

See accompanying notes to condensed consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS, continued

(In millions)

(Unaudited)

	Six Months Ended June 30, 2010	2009
Cash flows from financing activities:		
Proceeds from issuance of long-term debt	$ 249	$ 430
Payments on long-term debt	(186)	(142)
Proceeds from issuance of common stock, net of issuance costs	0	170
Borrowings on revolving credit facilities	0	82
Payments on revolving credit facilities	0	(213)
Borrowings (payments) on short-term debt, net	8	(72)
Dividends paid	(38)	(34)
Debt issuance costs	(2)	(4)
Noncontrolling interests capital contributions	0	7
Net cash provided by financing activities	**31**	**224**
Increase in cash and cash equivalents	32	48
Cash and cash equivalents, beginning of period	31	10
Cash and cash equivalents, end of period	**$ 63**	**$ 58**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 49	$ 35
Non-cash investing and financing activities:		
Accrued capital additions	23	52
Accrued dividends payable	20	20

See accompanying notes to condensed consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1: BASIS OF PRESENTATION

Nature of Business

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power and fuel marketers located throughout the western United States. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE s corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. The Company served 821,638 retail customers as of June 30, 2010.

Condensed Consolidated Financial Statements

These condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Certain information and footnote 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.

The financial information included herein for the three and six month periods ended June 30, 2010 and 2009 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 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, 2009 is derived from the Company s audited consolidated financial statements and notes thereto for the year ended December 31, 2009, included in Item 8 of PGE s Annual Report on Form 10-K, filed with the SEC on February 25, 2010, and should be read in conjunction with such consolidated financial statements.

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 contingent liabilities, 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.

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Recent Accounting Pronouncements

On January 1, 2010, PGE adopted Statement of Financial Accounting Standard No. (SFAS) 167, *Amendments to FASB Interpretation No. 46(R)*, (SFAS 167) which is a revision of FASB Interpretation No. 46(R), *Variable Interest Entities*, and changes how a company determines when a variable interest entity (VIE) should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity s purpose and design and a company s ability to direct the activities of the entity that most significantly impact the entity s economic performance. SFAS 167 requires a company to provide additional disclosures about its involvement with VIEs and what any significant change in risk exposure does to that involvement. A company is also required to disclose how its involvement with a VIE affects the company s performance. The adoption of SFAS 167, which was codified in the FASB Accounting Standards Codification 810, *Consolidation*, upon the adoption of SFAS 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162*, did not have a material impact on PGE s condensed consolidated financial position, condensed consolidated results of operations, or condensed consolidated cash flows.

Accounting Standards Update (ASU) 2010-06, *Fair Value Measurements and Disclosures (Topic 820) - Improving Disclosures about Fair Value Measurements* (ASU 2010-06) requires new disclosures about (i) the transfers in and out of Levels 1 and 2 and a description of the reasons for the transfers and (ii) for an entity to report separately about purchases, sales, issuances, and settlements for Level 3 fair value measurements. For additional information on the three broad levels, see Note 3. ASU 2010-06 also clarifies existing disclosures and requires (i) an entity to provide fair value measurement disclosures for each class of assets and liabilities and (ii) disclosures about inputs and valuation techniques. In accordance with the provisions of ASU 2010-06, on January 1, 2010, PGE adopted the requirements of ASU 2010-06, except for the disclosures about purchases, sales, issuance and settlements in the roll forward of activity in Level 3 fair value measurements, which did not have a material impact on PGE s consolidated financial position, consolidated results of operation, or consolidated cash flows. Based on the provisions of ASU 2010-06, PGE will adopt the disclosure requirements about purchases, sales, issuance and settlements in the roll forward of activity in Level 3 fair value measurements on January 1, 2011, which is not expected to have a material impact on PGE s consolidated financial position, consolidated results of operation, or consolidated cash flows.

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NOTE 2: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $5 million as of June 30, 2010 and December 31, 2009.

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

	Six Months Ended June 30,	
	2010	**2009**
Balance at beginning of period	$ 5	$ 4
Provision, net	3	5
Amounts written off, less recoveries	(3)	(4)
Balance at end of period	$ 5	$ 5

Inventories

Inventories consist primarily of materials, supplies, and fuel. Materials and supplies inventories are used in operations and maintenance and capital activities, and are recorded at average cost. Fuel inventories include natural gas, oil, and coal and are used in PGE s generating plants. Natural gas is recorded at the lower of average cost or market, with coal and oil recorded at average cost.

Electric Utility Plant, Net

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

	June 30, 2010	**December 31, 2009**
Electric utility plant	$ 5,819	$ 5,596
Construction work in progress	428	406
Total cost	6,247	6,002
Less: accumulated depreciation and amortization	(2,195)	(2,144)
Electric utility plant, net	$ 4,052	$ 3,858

Accumulated depreciation and amortization in the table above includes amortization of intangible assets of $129 million and $122 million as of June 30, 2010 and December 31, 2009, respectively. Amortization expense related to intangible assets was $4 million for both the three month periods ended June 30, 2010 and 2009 and $7 million and $8 million for the six months ended June 30, 2010 and 2009, respectively.

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Regulatory Assets and Liabilities

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

	June 30, 2010		December 31, 2009	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 157	$ 181	$ 118	$ 125
Pension and other postretirement plans	-	193	-	196
Deferred income taxes	-	87	-	91
Deferred broker settlements	22	1	49	1
Debt reacquisition costs	-	24	-	26
Utility rate treatment of income taxes	-	5	7	-
Boardman power cost deferral	-	-	17	-
Other	4	33	6	26
Total regulatory assets	$ 183	$ 524	$ 197	$ 465
Regulatory liabilities:				
Asset retirement removal costs	$ -	$ 565	$ -	$ 541
Asset retirement obligations	-	32	-	30
Utility rate treatment of income taxes	10	13	9	24
Trojan ISFSI pollution control tax credits	-	20	-	17
Other	8	35	18	42
Total regulatory liabilities	$ 18	$ 665	$ 27	$ 654

In the second quarter of 2010, the OPUC revised its administrative rules concerning the application of Oregon Senate Bill 408 (SB 408). These rule changes are effective beginning with the report for the 2009 reporting period. Based on PGE s evaluation of the revised rules, their application could result in a collection from customers ranging from $6 million to $10 million for the year ended December 31, 2009. Under the prior rules, PGE previously recorded a $13 million refund to customers for 2009. PGE s annual SB 408 report for 2009 will be filed with the OPUC by October 15, 2010, with a decision by the OPUC expected by April 2011. Based on uncertainties relating to the regulatory process, PGE continues to reflect the $13 million refund on the consolidated balance sheet and will continue to evaluate the amount recorded as the 2009 filing proceeds through the OPUC review process. Application of the revised rules is not expected to have a material impact to the SB 408 calculation for 2010, currently estimated to result in a $9 million collection from customers.

On February 12, 2010, the OPUC issued an order authorizing the offset of the Boardman power cost deferral with the simultaneous amortization of an equal amount of customer credits related to nuclear decommissioning activities. Based on the OPUC order, $19 million was transferred from the Nuclear decommissioning trust to PGE, which is included in the condensed consolidated statements of cash flows for the six months ended June 30, 2010.

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Credit Facilities

PGE has the following unsecured revolving credit facilities:

- A $370 million syndicated credit facility, with $10 million and $360 million scheduled to terminate in July 2012 and July 2013, respectively;

- A $200 million syndicated credit facility, which is scheduled to terminate in December 2012; and

- A $30 million credit facility, which is scheduled to terminate in June 2012.

Pursuant to the individual terms of the agreements, all credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. All credit facilities 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, 2010, PGE was in compliance with this covenant with a 53.7% debt ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the 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 $750 million through February 6, 2012. The authorization contains a standard provision that provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of June 30, 2010, PGE had $213 million in letters of credit under the credit facilities and had no borrowings or commercial paper outstanding. As of June 30, 2010, the aggregate credit available under the credit facilities was $387 million.

Long-term Debt

During the first half of 2010, PGE had the following long-term debt transactions:

- On June 15th, issued $58 million of 3.81% First Mortgage Bonds due June 2017, with interest payable semi-annually on June 15th and December 15th;

- On June 1st, repaid $17 million of 4.8% Port of St. Helens Pollution Control Revenue Bonds;

- On April 1st, repaid $20 million of 4.8% Port of St. Helens Pollution Control Revenue Bonds;

- On March 15th, repaid $149 million of 7.875% unsecured notes;

- On March 11th, remarketed $121 million of Pollution Control Revenue Bonds due May 2033 at 5.0%, with interest payable semi-annually on March 1st and September 1st, which are backed by first mortgage bonds; and

On January 15th, issued $70 million of 3.46% First Mortgage Bonds due January 2015, with interest payable semi-annually on January 15th and July 15th.

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As of June 30, 2010, the Company holds $21 million of Pollution Control Revenue Bonds, which can be remarketed through 2033.

Pension and Other Postretirement Benefits

The following table provides the components of net periodic benefit cost for the three months ended June 30 (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**
Service cost	$ 3	$ 3	$ -	$ -	$ -	$ -
Interest cost	7	8	1	1	-	-
Expected return on plan assets	(10)	(11)	-	-	-	-
Amortization of net actuarial loss	1	-	1	1	-	-
Net periodic benefit cost	$ 1	$ -	$ 2	$ 2	$ -	$ -

The following table provides the components of net periodic benefit cost for the six months ended June 30 (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**
Service cost	$ 6	$ 6	$ 1	$ 1	$ -	$ -
Interest cost	14	16	2	2	1	1
Expected return on plan assets	(20)	(22)	-	-	-	-
Amortization of net actuarial loss	2	-	1	1	-	-
Net periodic benefit cost	$ 2	$ -	$ 4	$ 4	$ 1	$ 1

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NOTE 3: FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments, both assets and liabilities recognized and not recognized in PGE s condensed consolidated balance sheets, for which it is practicable to estimate fair value is as follows as of June 30, 2010 and December 31, 2009:

The fair value of cash and cash equivalents approximate their carrying amounts due to the short-term nature of these balances;

Derivative instruments are recorded at fair value and are based on published market indices as adjusted for other market factors such as location pricing differences or internally developed models;

Certain trust assets, consisting of money market funds and fixed income securities included in the Nuclear decommissioning trust and marketable securities included in the Non-qualified benefit plan trust, are recorded at fair value and are based on quoted market prices; and

The fair value of long-term debt 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. As of June 30, 2010, the estimated aggregate fair value of PGE s long-term debt was $1,904 million, compared to its $1,808 million carrying amount. As of December 31, 2009, the estimated aggregate fair value of PGE s long-term debt was $1,818 million, compared to its $1,744 million carrying amount.

A fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. The three broad 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. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.

Level 2 - Pricing inputs are other than quoted market prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and swaps.

Level 3 - Pricing inputs include significant inputs that are generally less observable than objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers needs. At each balance sheet date, the Company performs an analysis of all instruments subject to fair value measurement and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

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

	Level 1	Level 2	Level 3	Total
As of June 30, 2010:				
Assets:				
Nuclear decommissioning trust*:				
Money market funds	$ 13	$ -	$ -	$ 13
Debt securities:				
U.S. treasury securities	3	-	-	3
Corporate debt securities	-	7	-	7
Mortgage-backed securities	-	5	-	5
Municipal securities	-	3	-	3
Asset-backed securities	-	2	-	2
Non-qualified benefit plan trust:				
Equity securities	17	1	-	18
Debt securities - mutual funds	3	-	-	3
Assets from price risk management activities*:				
Electricity	-	11	-	11
Natural gas	-	7	-	7
	$ 36	$ 36	$ -	$ 72
Liabilities - Liabilities from price risk management activities*:				
Electricity	$ -	$ 85	$ 23	$ 108
Natural gas	-	45	202	247
	$ -	$ 130	$ 225	$ 355
As of December 31, 2009:				
Assets:				
Nuclear decommissioning trust*:				
Money market funds	$ 31	$ -	$ -	$ 31
Debt securities:				
U.S. treasury securities	4	-	-	4
Corporate debt securities	-	8	-	8
Mortgaged-backed securities	-	5	-	5
Municipal securities	-	2	-	2
Non-qualified benefit plan trust:				
Equity securities	21	-	-	21
Debt securities - mutual funds	4	-	-	4
Assets from price risk management activities*:				
Electricity	-	7	-	7
Natural gas	-	6	-	6
	$ 60	$ 28	$ -	$ 88
Liabilities - Liabilities from price risk management activities*:				
Electricity	$ -	$ 72	$ 9	$ 81
Natural gas	-	29	145	174
	$ -	$ 101	$ 154	$ 255

* 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.

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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 levels.

Nuclear decommissioning trust assets reflect the assets held in trust to fund general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and consist of money market funds and fixed income securities. Non-qualified benefit plan trust reflects the assets held in trust to fund a portion of the obligations of PGE s non-qualified benefit plans and consist primarily of marketable securities. The Non-qualified benefit plan trust also holds insurance policies recorded at cash surrender value and are excluded from the preceding table as they are not recorded at fair value.

Assets and liabilities from price risk management activities represent derivative transactions entered into by PGE to manage its exposure to commodity price risk and minimize net power costs for service to the Company s retail customers and may consist of forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil. PGE applies a market-based approach to the fair value measurement of its derivative transactions. Inputs into the valuation of derivative activities include forward commodity and foreign exchange pricing, interest rates, volatility and correlation. PGE utilizes the Black-Scholes and Monte Carlo pricing models for commodity option contracts. Forward pricing, which employs the mid-point of the market s bid-ask spread, is derived using observed transactions in active markets, as well as historical experience as a participant in those markets, and is validated against nonbinding quotes from brokers with whom the Company transacts. Interest rates used to calculate the present value of derivative valuations incorporate PGE s borrowing ability. The Company also considers the liquidity of delivery points of executed transactions when determining where in the fair value hierarchy a transaction should be classified. PGE considers its creditworthiness and the creditworthiness of its counterparties when determining the appropriateness of a particular transaction s assigned Level in the fair value hierarchy.

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,	
	2010	**2009**	**2010**	**2009**
Net liabilities from price risk management activities as of beginning of period	$ (221)	$ (170)	$ (154)	$ (123)
Net realized and unrealized gains (losses)	(2)	17	(59)	(34)
Purchases, issuances and settlements, net	(2)	(3)	(12)	1
Net liabilities from price risk management activities as of end of period	$ (225)	$ (156)	$ (225)	$ (156)

Net realized and unrealized gains (losses) are recorded in Purchased power and fuel expense in the condensed consolidated statements of income, and include ($2) million and $17 million for the three months ended June 30, 2010 and 2009, respectively, and ($59) million and ($29) million for the six months ended June 30, 2010 and 2009, respectively, of Level 3 net realized and unrealized gains (losses) that have been fully offset by the effects of regulatory accounting. Transfers into Level 3 occur when significant inputs used to value the Company s derivative instruments become less observable, such as a

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delivery location becoming significantly less liquid. Transfers out of Level 3 occur when the significant inputs become more observable, such as 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.

NOTE 4: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generating resources 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 power purchases and sales resulting from economic dispatch decisions for Company-owned generation. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, where adverse changes in prices and/or rates may affect the Company s financial position, performance, or cash flow.

PGE utilizes derivative instruments, which may include forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil, in its wholesale electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk, mitigate the effects of market fluctuations, and minimize net power costs for service to its retail customers. These derivative instruments are recorded at fair value on the balance sheet, with changes in fair value recorded in the statement of income. However, as a regulated entity, PGE recognizes a regulatory asset or liability in order to defer gains and losses from derivative activity until realized, in accordance with the ratemaking and cost recovery process authorized by the OPUC. This accounting treatment defers the mark-to-market gains and losses on derivative activities until settlement. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as purely economic hedges. PGE does not engage in trading activities for non-retail purposes.

PGE has elected not to net on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists.

PGE s net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions were as follows (in millions):

Type	June 30, 2010		December 31, 2009	
Commodity contracts:				
Electricity	11	MWh	12	MWh
Natural gas	102	Decatherms	96	Decatherms
Foreign exchange	$7	Canadian	$5	Canadian

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The fair value of PGE s Assets and Liabilities from price risk management activities consists of the following (in millions):

	June 30, 2010	December 31, 2009
Current assets:		
Commodity contracts:		
Electricity	$ 9	$ 6
Natural gas	6	5
Total current derivative assets	15[(1)]	11[(1)]
Noncurrent assets:		
Commodity contracts:		
Electricity	2	1
Natural gas	1	1
Total noncurrent derivative assets	3[(2)]	2[(2)]
Total derivative assets not designated as hedging instruments	$ 18	$ 13
Total derivative assets	$ 18	$ 13
Current liabilities:		
Commodity contracts:		
Electricity	$ 68	$ 57
Natural gas	104	71
Total current derivative liabilities	172	128
Noncurrent liabilities:		
Commodity contracts:		
Electricity	40	24
Natural gas	143	103
Total noncurrent derivative liabilities	183	127
Total derivative liabilities not designated as hedging instruments	$ 355	$ 255
Total derivative liabilities	$ 355	$ 255

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Commodity contracts:				
Electricity	$ (6)	$ 12	$ (59)	$ (69)
Natural Gas	(18)	5	(109)	(83)
Oil	-	(1)	-	(1)

Unrealized gains and losses and certain realized gains and losses presented in the table above are offset within the statement of income by the effects of regulatory accounting. Of the net gain (loss) recognized in net income for the three months ended June 30, 2010 and 2009, ($25) million and $4 million, respectively, have been offset. Of the net loss recognized in net income for the six months ended June 30, 2010 and 2009, ($159) million and ($167) million, respectively, have been offset.

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, 2010 related to PGE s derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2010	**2011**	**2012**	**2013**	**2014**	**Total**
Commodity contracts:						
Electricity	$ 20	$ 52	$ 13	$ 8	$ 4	$ 97
Natural gas	65	77	65	30	3	240
Net unrealized loss	$ 85	$ 129	$ 78	$ 38	$ 7	$ 337

The Company 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 the Company s unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties and 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, 2010 was $297 million, for which the Company has $193 million in posted collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at June 30, 2010, the cash requirement would have been $283 million.

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Counterparties representing 10% or more of Assets and Liabilities from price risk management activities as of June 30, 2010 or December 31, 2009 were as follows:

	June 30, 2010	December 31, 2009
Assets from price risk management activities:		
Counterparty A	31%	41%
Counterparty B	16	14
Counterparty C	8	15
	55%	70%
Liabilities from price risk management activities:		
Counterparty A	21%	19%
Counterparty C	10	13
Counterparty D	11	14
	42%	46%

See Note 3 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

Components of basic and diluted earnings per share were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Numerator (in millions):				
Net income attributable to Portland General Electric Company common shareholders	$ 24	$ 24	$ 51	$ 55
Denominator (in thousands):				
Weighted-average common shares outstanding - basic	75,276	75,131	75,253	70,352
Dilutive effect of unvested restricted stock units and employee stock purchase plan shares	14	104	15	95
Weighted-average common shares outstanding - diluted	75,290	75,235	75,268	70,447
Earnings per share - basic and diluted	$ 0.32	$ 0.31	$ 0.68	$ 0.77

Unvested performance stock units and related dividend equivalent rights are not included in the computation of dilutive securities because vesting of these instruments is dependent upon three-year performance periods and the vesting criteria have not been met as of the end of the reporting period presented.

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Basic and diluted earnings per share amounts are calculated based on actual amounts rather than the rounded amounts presented in the table above and on the condensed consolidated statements of income. Accordingly, calculations using the rounded amounts presented for net income and weighted average shares outstanding may yield results that vary from the earnings per share amounts presented in the table above.

NOTE 6: COMPREHENSIVE INCOME

Comprehensive income is as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income	**$ 24**	**$ 26**	**$ 51**	**$ 50**
Pension and other postretirement plans funded position, net of taxes	1	1	3	1
Reclassification of defined benefit pension plan and other benefits to a regulatory asset, net of taxes	(1)	(1)	(3)	(1)
Comprehensive income	24	26	51	50
Less: comprehensive income (loss) attributable to noncontrolling interests	-	2	-	(5)
Comprehensive income attributable to Portland General Electric Company	**$ 24**	**$ 24**	**$ 51**	**$ 55**

NOTE 7: CONTINGENCIES

Legal Matters

Trojan Investment Recovery

Background. In 1993, PGE closed the Trojan Nuclear 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. 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.

Court Proceedings on OPUC Authority to Grant Recovery of Return on Trojan Investment. Numerous challenges, appeals and reviews 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. The primary plaintiffs in the litigation were the Citizens Utility Board (CUB) and the Utility Reform Project (URP). In 1998, the Oregon Court of Appeals upheld the OPUC order authorizing PGE s recovery of the Trojan investment, but held that the OPUC did not have the authority to allow PGE to recover a return on the Trojan investment and remanded the case to the OPUC for reconsideration.

In 2000, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE s recovery of, and return on, its investment in Trojan. The URP did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements.

In March 2002, the OPUC issued an order (2002 Order) denying all of the URP s challenges, and approving the accounting and ratemaking elements of the 2000 settlement. 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.

On September 30, 2008, the OPUC issued an order that required PGE to refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period October 1, 2000 to September 30, 2001. The $15.4 million amount, plus accrued interest, resulted in a total refund of $33.1 million, payment of which was completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below have separately appealed the order to the Oregon Court of Appeals.

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

In August 2006, the Oregon Supreme Court issued a ruling abating the class action proceedings until the OPUC responded with respect to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000.

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.

In October 2006, the Marion County Circuit Court abated the class actions in response to the ruling of the Oregon Supreme Court. In October 2007, the Class Action Plaintiffs filed a motion to lift the abatement. In February 2009, the Circuit Court denied the motion.

Management cannot predict the ultimate outcome of the above matters. However, it believes that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in future reporting periods.

Complaint and Application for Deferral Income Taxes

On October 5, 2005, the URP and another party (together, the Complainants) filed a Complaint and an Application for Deferred Accounting with the OPUC alleging that, since the September 2, 2005 effective date of SB 408, PGE s rates were not just and reasonable and were in violation of SB 408 because they contained approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any governmental entity. The Complaint and Application for Deferred Accounting requested that the OPUC order the creation of a deferred account for all amounts charged to customers since September 2, 2005 for state and federal income taxes, less amounts actually paid by or on behalf of PGE to the federal and state governments for income taxes.

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In August 2007, the OPUC issued an order granting the Application for Deferred Accounting for the period from October 5, 2005 through December 31, 2005. The OPUC s order also dismissed the Complaint, on grounds that it was superfluous to the Complainants application for deferred accounting.

In August 2009, the OPUC issued an order that denied amortization of any deferral in this matter, based on a review of PGE s earnings over the twelve - month period ended September 30, 2006.

On October 16, 2009, Complainants filed an appeal of the August 2009 order with the Oregon Court of Appeals.

Management cannot predict the ultimate outcome of this matter. However, management believes this matter will not have a material adverse effect on PGE s financial condition, results of operations or cash flows.

Turlock Irrigation District Claim

PGE and Power Resources Cooperative (PRC) are parties to an Ownership and Operation Agreement (OOA), pursuant to which PRC is entitled to ten percent of the power generated at Boardman. In 1992, PRC entered into a power purchase agreement with Turlock Irrigation District (Turlock) in which PRC agreed to provide Turlock with its share of the Boardman output. In October 2005, Boardman experienced an outage that extended into 2006.

In 2007, Turlock filed a lawsuit against PGE in Multnomah County Circuit Court in the state of Oregon, alleging breach of contract, negligence, and gross negligence, and seeking damages in excess of $15 million as a result of having to purchase power in the open market to replace lost output from Boardman during the outage. The complaint further alleges that PRC assigned its litigation rights relating to the outage to Turlock pursuant to an assignment agreement executed in 2007.

PGE sought and received an order joining PRC as a necessary party to the litigation. PRC intervened as a plaintiff, also alleging breach of contract and damages in the amount alleged by Turlock, for the purpose of reimbursing Turlock for those expenses.

In August 2009, PGE filed a motion for summary judgment asserting, among other things, that Turlock does not have standing to bring a contract or tort claim against PGE, that damages based on economic loss are not recoverable under a tort claim, and that, under the OOA, the parties have waived the right to bring tort claims based on a theory of negligence. In November 2009, the Court denied PGE s motion for summary judgment. A trial has been scheduled for February 2011.

Management cannot predict the ultimate outcome of this matter. However, management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE s results of operations and cash flows in future reporting periods.

City of Glendale Claim

In September 1988, PGE and the City of Glendale, California (Glendale) entered into a Long-Term Power Sale and Exchange Agreement (Agreement) pursuant to which Glendale purchases up to 20 MW of firm system capacity from PGE as scheduled by Glendale. The Agreement remains effective until 2012. In 2005, Glendale disputed the price that PGE had been charging for power under the contract and requested refunds. In addition, Glendale asserted that the closure of Trojan triggered a duty under the Agreement to renegotiate price terms.

On August 25, 2005, PGE filed a complaint against Glendale, requesting a declaratory ruling that PGE does not owe Glendale any refunds under the Agreement. In response to PGE s complaint, Glendale filed a counterclaim against PGE seeking approximately $23.3 million, plus interest.

The parties reached a settlement in April 2010. Under the settlement, future payments from Glendale were reduced by approximately $2 million over the remaining life of the contract and the contract was amended to clarify certain provisions. On April 7, 2010, the trial court dismissed the lawsuit. The settlement was accepted by the FERC on July 1, 2010.

Regulatory Matters

Pacific Northwest Refund Proceeding

In July 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 June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of the FERC order to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued its decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to: (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings; (ii) include sales to CERS in its analysis; and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC s findings based on the record established by the administrative law judge and did not rule on the FERC s ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit in April 2009 issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC. In January 2010, the Supreme Court of the United States denied a petition for certiorari filed by various sellers, including PGE.

Since issuance of the mandate, certain parties proposing refunds have filed pleadings with the FERC suggesting procedures on remand, attempting to initiate new proceedings, and containing additional evidence that they assert shows market-wide manipulation that justifies refunds from early in 2000. Parties opposing refunds, including PGE, have filed various pleadings that contest allegations of market-wide manipulation and urge the FERC to reaffirm, with a more detailed explanation of its consideration of market manipulation claims, its previous decision not to initiate proceedings to order refunds.

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 as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

Management cannot predict the outcome of the Pacific Northwest Refund proceeding, or whether the FERC will order refunds in this proceeding, and if so, how such refunds would be calculated. However, management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE s results of operations and cash flows in future reporting periods.

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FERC Investigation

In May 2008, PGE received a notice of a preliminary non-public investigation from the FERC Division of Investigations concerning PGE s compliance with its Open Access Transmission Tariff. The investigation involved certain issues identified during an audit by FERC staff.

On June 4, 2010, the FERC issued an order finalizing a stipulation and consent agreement to resolve the investigation. Under the agreement, PGE paid a civil penalty of $375,000 and agreed to submit semi-annual compliance monitoring reports for at least one year.

Environmental Matters

Portland Harbor

A 1997 investigation by the U.S. Environmental Protection Agency (EPA) of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included this segment on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river.

The Portland Harbor site is currently undergoing a remedial investigation and feasibility study (RI/FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs, not including PGE. In the AOC, the EPA determined that the RI/FS would focus on a segment of the river approximately 5.7 miles in length.

In January 2008, the EPA requested information from various parties, including PGE, concerning properties in or near the segment of the river being examined in the RI/FS, as well as several miles beyond that 5.7 mile segment. Subsequently, the EPA has listed 27 additional PRPs.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision that the EPA expects to issue in 2012, in which it will document its findings and select a preferred cleanup alternative.

Sufficient information is currently not available to determine the total cost of any required investigation or remediation of the Portland Harbor site or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. However, management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE s results of operations and cash flows in future reporting periods.

Harbor Oil

Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company s power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil continues to be utilized by other entities for the processing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls, have been detected at the site. In September 2003, the EPA included the Harbor Oil facility on the National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for RI/FS from the EPA, dated June 27, 2005, in which the Company was named as one of 14 PRPs with respect to the Harbor Oil site. In May 2007, an Administrative Order on Consent was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The EPA has approved an RI/FS work plan. The RI commenced in 2008 and is continuing.

Sufficient information is currently not available to determine the total cost of investigation and remediation of the Harbor Oil site or the liability of the PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. However, management believes that the outcome of this matter will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE s results of operations and cash flows in future reporting periods.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings that arise from time to time in the ordinary course of its business, which may result in adverse judgments against the Company. Although management currently believes that resolution of such matters will not have a material adverse effect 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 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 PGE s historical experience and the evaluation of the specific indemnities. As of June 30, 2010, 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.

PGE has a loan guarantee to a financial institution that has provided a loan to one of the variable interest entities with which PGE is involved, for the construction of photovoltaic solar generating facilities. For further information on PGE s relationship with variable interest entities, see Note 9. The maximum amount available pursuant to the loan agreement is $13.1 million, with the maximum potential amount that PGE could be required to pay pursuant to the guarantee equal to the amount outstanding under the loan at the time of default, plus any outstanding interest. As of June 30, 2010, approximately $8 million is outstanding under this loan agreement, which is included in Other current liabilities on PGE s condensed consolidated balance sheet. PGE has no recourse to any party for any amount it could be required to pay pursuant to this guarantee.

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NOTE 9: VARIABLE INTEREST ENTITIES

PGE has determined that its interest in three VIEs, as outlined below, contains the obligation to absorb the variability of the entities that could potentially be significant to the VIEs, and the power to direct the activities that most significantly affect the entities economic performance. Accordingly, the VIEs are consolidated within the Company s condensed consolidated financial statements. All three arrangements were formed for the sole purpose of designing, developing, constructing, owning, maintaining, operating, and financing photovoltaic solar power facilities located on real property owned by third parties and selling the energy generated by the facilities. PGE is the Managing Member in each of the Limited Liability Companies (LLCs), holding less than 1% equity interest in each entity, and a financial institution is the Investor Member, holding more than 99% equity interest in each entity. As the primary beneficiary, PGE consolidates the VIEs.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining it is the primary beneficiary of these LLCs include the following: (1) PGE has the expertise to own and operate electric generating facilities and is authorized to operate the LLCs pursuant to the operating agreements, and, therefore, PGE has control over the most significant activities of the LLCs; (2) PGE expects to own 100% of the LLCs shortly after five years have elapsed, at which time the facilities will have approximately 75% of their estimated useful life remaining; and (3) based on projections prepared in accordance with the operating agreement, PGE expects to absorb a majority of the expected losses of the LLCs.

During 2009, impairment losses of $5 million, which are classified in Depreciation and amortization expense, were recognized on photovoltaic solar power facilities held by one LLC. Based on PGE s intent to ultimately acquire 100% of the LLC and the fact that the capitalized cost of the photovoltaic solar power facilities exceeded the undiscounted cash flows of the facilities over their estimated useful lives, an impairment analysis was performed at the time each facility was completed. Immediately following the completion of the photovoltaic solar power facilities, an impairment loss was recognized on these assets. The impairment losses were equal to the excess of the carrying amount over the estimated fair value of these photovoltaic solar power facilities. Estimated fair value was determined using the discounted cash flow method, with the new cost basis of these photovoltaic solar power facilities to be amortized over the remaining estimated useful lives.

As noted above, PGE has consolidated the VIEs even though it has less than a 1% ownership interest in the LLCs. The participating members are allocated their proportionate share of the LLCs net losses based on the respective members ownership percent. Accordingly, the majority of the impairment losses, which are included in the net losses of the LLCs, are attributable to the noncontrolling interests through the Net loss attributable to the noncontrolling interests in PGE s condensed consolidated statements of income.

Included in PGE s consolidated balance sheet as of June 30, 2010 and December 31, 2009 are LLC assets with carrying amounts totaling $10.1 million and $1.8 million, respectively, substantially all of which are classified as Electric utility plant, net. These assets can only be used to settle the obligations of the consolidated VIEs. As of June 30, 2010, the LLCs liabilities totaled $8.2 million, substantially all of which are classified as Other current liabilities, while as of December 31, 2009, the LLCs total liabilities were nominal.

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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 relate to expectations, beliefs, plans, objectives for future operations, assumptions, business prospects, 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, should, estimates, expects, intends, plans, predicts, projects, will likely continue, 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 assets and facilities, operation and construction of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;

- the outcome of legal and regulatory proceedings and issues including, but not limited to, the proceedings related to the Trojan Investment Recovery, the Pacific Northwest Refund proceeding, the Portland Harbor investigation, and other matters described in Note 7, Contingencies, in the Notes to Condensed Consolidated Financial Statements;

- unseasonable or extreme weather and other natural phenomena, which in addition to affecting customers demand for power, could significantly affect PGE s ability and cost to procure adequate supplies of fuel or power to serve its customers, and could increase PGE s costs to maintain its generating facilities and transmission and distribution systems;

- operational factors affecting PGE s power generation facilities, including forced outages, hydro conditions, wind conditions, and disruption of fuel supply, which may cause the Company to incur replacement power costs or repair costs;

- the continuing effects of weak economies in the state of Oregon and the United States, including decreased demand for electricity and reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial soundness of vendors and service providers or elevated levels of uncollectible customer accounts;

- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper and the availability and cost of capital, 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 costs, and the repayments of maturing debt;

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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 pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, in order to mitigate carbon dioxide, mercury, and other gas emissions;

wholesale prices for natural gas, coal, oil, and other fuels and their impact on the availability and price of wholesale power in the western United States;

declines in wholesale power and natural gas prices, which would require the Company to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to existing purchased power and natural gas agreements;

changes in residential, commercial, and industrial growth and demographic patterns in PGE s service territory;

the effectiveness of PGE s risk management policies and procedures and the creditworthiness of customers and counterparties;

the failure to complete capital projects on schedule and within budget;

the effects of Oregon law related to utility rate treatment of income taxes, which may result in earnings volatility and affect PGE s results of operation;

the outcome of efforts to relicense the Company s hydroelectric projects, as required by the FERC;

declines in the market prices of equity securities held by, and increased funding requirements for, defined benefit pension plans and other benefit 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;

employee workforce factors, including aging, potential strikes, work stoppages, and transitions in senior management;

general political, economic, and financial market conditions;

natural disasters and other natural 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.

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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, 2009, and other periodic and current reports filed with the SEC.

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

The Company s revenues and income from operations can fluctuate during the year due to the impacts of seasonal weather conditions on demand for electricity, price changes, customer usage patterns (which can be affected by the local economy), and the availability and price of purchased power and fuel. PGE is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand - Retail energy deliveries in the first half of 2010 decreased approximately 5% from the same period last year as a result of warmer than normal weather in the first quarter of 2010 and the continued effects of a weak economy and high unemployment, with residential, commercial and industrial deliveries decreasing 6.7%, 4.4% and 0.4%, respectively. Slightly higher energy deliveries in the second quarter of 2010 partially offset the large decrease in the first quarter. On a weather adjusted basis, energy deliveries to retail customers in the first half of 2010 decreased 3.4%, primarily due to the effects of the economy, despite an approximate 4,000 increase in the average number of customers.

The average seasonally adjusted unemployment rates for the first halves of 2010 and 2009 are as follows:

	United States	Oregon	Portland/ Salem
2010			
First quarter	9.7%	10.6%	10.3%
Second quarter	9.7	10.6	10.4
Year-to-date	9.7	10.6	10.3
2009			
First quarter	8.2	10.6	9.8
Second quarter	9.3	12.1	11.9
Year-to-date	8.7	11.4	10.9

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PGE projects that weather adjusted retail energy deliveries for 2010 will be approximately 1% to 1.5% below 2009 levels. Based on deliveries for the first half of 2010, the Company anticipates that energy deliveries to paper products manufacturers will be down from earlier projections and continued economic pressure on commercial customers will combine to result in lower 2010 deliveries than in 2009. Such declines are expected to be partially offset by a moderate increase in deliveries to other existing industrial customers, including those in the high technology sector.

Power Operations - To meet the energy and capacity needs of its customers, the Company utilizes a combination of its own generating resources and wholesale market transactions. Based on numerous factors, including plant availability, customer demand, and current wholesale prices, PGE makes economic dispatch decisions continuously throughout a given period in an effort to minimize power costs for its retail customers. As a result, the proportion of power generated and purchased in the wholesale market to meet the Company s retail load requirement can vary from period to period. Although PGE s total system load in the first half of 2010 was comparable to that for the first half of 2009, generation was greater in 2010 than in 2009 as a result of extended maintenance outages and economic curtailments of certain plants in 2009.

During the first half of 2010, the Company s generating plants provided approximately 60% of its retail load requirement, compared to 48% in the first half of 2009. Availability of the plants PGE operates approximated 92% and 84% in the first half of 2010 and 2009, respectively. The availability of Colstrip, which PGE does not operate, approximated 96% and 72% in the first half of 2010 and 2009, respectively.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia projects decreased 14% in the first half of 2010 from the first half of 2009. These resources provided approximately 25% of the Company s retail load requirement in the first half of 2010, compared to 29% in the first half of 2009. Energy received from these sources fell short of projections in the Company s Annual Power Cost Update Tariff (AUT) by approximately 10% and 3% in the first half of 2010 and 2009, respectively. Such projections, which are finalized and filed with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year. Any shortfall in hydro generation from that projected in the AUT is generally replaced with power from higher cost sources. Energy from hydro resources is expected to be below normal for 2010.

PGE s Biglow Canyon wind farm is an important part of the Company s strategy to comply with Oregon s Renewable Energy Standard (RES). As of June 30, 2010, PGE has a total of 152 wind turbines in service at Biglow Canyon, with a capacity of approximately 300 MW. During the second quarter of 2010, 11 wind turbines were placed in service at Biglow Canyon Phase III. Phase III is the last phase at Biglow Canyon and will consist of 76 wind turbines, with a capacity of approximately 175 MW. The remaining 65 wind turbines are expected to be completed and placed in service in the third quarter of 2010. In the first half of 2010, wind generation increased 86% compared to the first half of 2009, primarily a result of Phase II becoming operational during the second and third quarters of 2009, and provided 4% of PGE s retail load requirement compared to 2% in the first half of 2009.

General Rate Case - Regulatory review of PGE s 2011 General Rate Case, filed with the OPUC in February 2010, is continuing, with a final order expected to be issued by mid-December 2010 and new prices expected to become effective January 1, 2011. PGE s initial filing proposed a $125 million increase in annual revenues, which includes a reduction in net variable power costs (NVPC) of $33 million, representing an approximate 7.4% overall increase in customer prices. The initial filing also included a proposed capital structure of 50% debt and 50% equity, a return on equity of 10.5%, and a cost of capital of 8.289%.

PGE, OPUC staff, and customer groups have reached agreement that resolves all revenue requirement issues in the case, all of which are subject to OPUC approval. The stipulated items, along with NVPC forecast updates filed recently, result in an increase of approximately $52 million in annual revenues. This revised revenue requirement includes a reduction in NVPC of $48 million and represents an approximate 3% overall increase in prices to customers. A summary of the revised revenue requirement increase is as follows (in millions):

	General Rate Case*	Net Variable Power Costs	Total
Original filing	$ 158	$ (33)	$ 125
Revenue requirement stipulations	(48)	-	(48)
Cost of capital stipulation	(15)	-	(15)
NVPC update	5	(15)	(10)
Total	$ 100	$ (48)	$ 52

* - Forecasted 2011 NVPC will be updated at various dates through November 2010. In addition, the load forecast will be updated in September. These updates may impact the amounts presented.

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The stipulated items reflect the following:

- Capital structure of 50% debt and 50% equity;
- Return on equity of 10.0%;
- Cost of capital of 8.033%;
- Updates of expected costs for 2011 based on the availability of better information;
- Expected changes in the timing of recovery of certain costs, and changes to estimates or assumptions used in forecasting certain operating items. PGE agreed to remove four capital projects expected to be placed in service in 2011 from the proposed 2011 average rate base, with the OPUC staff and customer groups supporting the use of deferred accounting that would begin at the time the related capital project is placed in service; and
- Fixed Power Cost Adjustment Mechanism (PCAM) deadband range to $15 million below and $30 million above the baseline NVPC.

Among the stipulated items, PGE and certain parties have agreed, subject to OPUC approval, to allow changes in customer prices to reflect the incremental revenue requirement impact of a shortened Boardman operating life, if that were to occur. The remaining investment in Boardman, which is approximately $124 million as of June 30, 2010, would increase with the addition of emissions controls and any decommissioning and other costs related to the plant s closure.

The Company s 2011 General Rate Case filing, as well as copies of direct testimony and exhibits and stipulations, is available on the OPUC Internet website at www.puc.state.or.us.

Capital Requirements and Financing - PGE s 2010 capital requirements are related primarily to the following major projects and debt maturities:

- Construction of Biglow Canyon Phase III, the smart meter project, and ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution and generation infrastructure. Capital expenditures are expected to approximate $495 million in 2010, of which $264 million has been incurred during the first half of the year. See the Capital Requirements section of this Item 2.
- The maturity of $186 million of long-term debt in 2010, of which $149 million matured in the first quarter and $37 million matured in the second quarter of 2010.

To fund these projects and debt maturities, the Company has issued a total of $249 million of long-term debt and generated $246 million of cash from operations in the first half of 2010. PGE expects cash from operations to approximate $470 million in 2010. For further information, see the Debt and Equity Financings section of this Item 2.

The Company s Integrated Resource Plan (IRP) was originally filed with the OPUC in November 2009 and included a strategy for the acquisition of new resources through 2015 and a 20-year strategy that outlines long-term expectations for resource needs and portfolio performance. The strategy encompasses energy efficiency measures and future plans for Boardman, as well as the following generation and transmission actions:

- A natural gas facility to meet additional base load requirements, estimated to 300 MW to 500 MW;
- A natural gas facility for additional peak load requirements, estimated up to 200 MW;
- Renewable resources to meet Oregon s Renewable Portfolio Standard requirements of 15% by 2015, estimated at 122 MWa; and
- A new transmission project called Cascade Crossing.

Future capital requirements will depend on whether the OPUC acknowledges the IRP, as the Company plans to issue requests for proposals (RFPs) shortly after acknowledgement is received. In each of the RFPs, the Company plans to include self-build options. For additional information about the IRP and emissions controls for the Boardman plant, see *Boardman emissions controls* and *IRP process* in the Capital Requirements section of this Item 2.

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 matters related 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
- Investigation of environmental matters at Portland Harbor.

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

Certain regulatory items impacted the Company s revenues, results of operations, or cash flows during the first half of 2010 as indicated below and may have affected customer prices, as authorized by the OPUC. In some cases, the Company deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, dependent on OPUC authorization.

- Power Costs - Pursuant to the Annual Power Cost Update Tariff (AUT) process, PGE annually files an estimate of power costs for the following year, with new prices to become effective January 1st each year. The AUT for 2010 resulted in an estimated $68 million, or 4%, decrease in the Company s annual retail revenue requirement, effective January 1, 2010, to reflect an expected decrease in power costs.

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Renewable Resource Costs - The renewable adjustment clause (RAC) mechanism allows the recovery of operating costs and impacts the results of operations only to the extent of providing a return on the Company s investment, however it will result in an increase in cash flows during future years to provide for recovery of the initial capital expenditures for the renewable resources.

In 2009, PGE filed for recovery of its investments in Biglow Canyon Phase II and certain solar generating facilities, which resulted in an overall $42 million increase in annual retail revenues, effective January 1, 2010.

In 2010, PGE filed for recovery of, among other things, the deferral of eligible costs and a return on its investment related to Biglow Canyon Phase III, estimated at $17 million. Effective January 1, 2011, the revenue requirements related to Biglow Canyon Phase III are expected to be reflected in retail prices through the Company s 2011 General Rate Case.

Selective Water Withdrawal (SWW) project costs - In January 2010, the Selective Water Withdrawal structure at PGE s Pelton/Round Butte hydroelectric project was completed. Effective February 1, 2010, the Company has been allowed an annualized revenue requirement of $9.8 million related to this capital project.

Utility Rate Treatment of Income Taxes (SB 408)

Following its review of PGE s tax report for the calendar year 2008, the OPUC issued an order on April 6, 2010 that authorized the Company to refund to retail customers approximately $9.6 million recorded as a regulatory liability in 2008, plus accrued interest, over a one-year period that began June 1, 2010.

During 2009, the Company recorded a $13 million potential refund that, pending OPUC review, is expected to be credited to customers over the twelve month period beginning June 1, 2011. For further information regarding SB 408, see *Regulatory Assets and Liabilities* of Note 2, Balance Sheet Components, in the Notes to Condensed Consolidated Financial Statements.

For the first half of 2010, the Company has recorded a potential $4 million collection from customers, which would be reflected in customer prices beginning June 1, 2012.

Decoupling - The decoupling mechanism provides for customer collection if weather adjusted use per customer is less than that approved in the Company s most recent general rate case.

In April 2010, the OPUC authorized the Company to refund to retail customers approximately $2.7 million related to the twelve month period ended January 31, 2010, as weather adjusted use per customer exceeded that approved in the 2009 General Rate Case. Revenues were adjusted during the corresponding period, while credits to customers began June 1, 2010 and will continue over a one-year period.

For the twelve month period beginning February 1, 2010, the Company has recorded an estimated collection of $4 million, which would be collected from customers over a one year period beginning June 1, 2011.

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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, 2009, filed with the SEC on February 25, 2010.

Results of Operations

The following table contains certain financial information for the periods presented (dollars in millions):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 415	100%	$ 389	100%	$ 864	100%	$ 874	100%
Operating expenses:								
Purchased power and fuel	186	45	184	47	410	47	439	50
Production and distribution	46	11	43	11	85	10	85	10
Administrative and other	48	11	46	12	93	11	91	10
Depreciation and amortization	57	14	50	13	114	13	107	12
Taxes other than income taxes	21	5	21	5	44	5	44	5
Total operating expenses	358	86	344	88	746	86	766	87
Income from operations	57	14	45	12	118	14	108	13
Other income (expense):								
Allowance for equity funds used during construction	4	1	6	2	8	1	8	1
Miscellaneous income (expense), net	(3)	(1)	4	1	(2)	-	1	-
Other income, net	1	0	10	3	6	1	9	1
Interest expense	26	6	26	7	55	7	51	6
Income before income taxes	32	8	29	8	69	8	66	8
Income taxes	8	2	3	1	18	2	16	2
Net income	**24**	**6**	**26**	**7**	**51**	**6**	**50**	**6**
Less: net income (loss) attributable to noncontrolling interests	-	-	2	1	-	-	(5)	-
Net income attributable to Portland General Electric Company	**$ 24**	**6%**	**$ 24**	**6%**	**$ 51**	**6%**	**$ 55**	**6%**

Net income attributable to Portland General Electric Company was $24 million, or $0.32 per diluted share, for the second quarter of 2010 compared to $24 million, or $0.31 per diluted share, for the second quarter of 2009. Despite an increase in the number of customers served, retail energy deliveries were comparable to the second quarter of 2009 due to both a continued weak economy and cooler weather in the second quarter of 2010. Operating results were positively impacted by the effects of SB 408, with such results partially offset by changes in the fair market values of the non-qualified benefit plan trust assets.

Net income attributable to Portland General Electric Company was $51 million, or $0.68 per diluted share, for the six months ended June 30, 2010 compared to $55 million, or $0.77 per diluted share, for the six months ended June 30, 2009. Both the weak economy and milder weather resulted in an approximate 5% decrease in retail energy deliveries in the first half of 2010. Partially offsetting the impact of lower energy deliveries was a decrease in the average cost of purchased power and the effects of SB 408.

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Second Quarter of 2010 Compared to the Second Quarter of 2009

Revenues, energy deliveries (based in megawatt hours), and average number of retail customers consist of the following:

	Three Months Ended June 30, 2010 Amount	2010 % of Total	2009 Amount	2009 % of Total
Revenues (dollars in millions):				
Retail:				
Residential	$ 183	44%	$ 180	47%
Commercial	145	35	155	40
Industrial	54	13	40	10
Subtotal	382	92	375	97
Other - accrued revenues	4	1	(15)	(4)
Total retail revenues	386	93	360	93
Wholesale revenues	21	5	21	5
Other operating revenues	8	2	8	2
Total revenues	$ 415	100%	$ 389	100%
Energy deliveries* (MWh in thousands):				
Retail:				
Residential	1,685	32%	1,646	32%
Commercial	1,742	33	1,816	36
Industrial	969	19	924	18
Total retail energy deliveries	4,396	84	4,386	86
Wholesale energy deliveries	814	16	688	14
Total energy deliveries	5,210	100%	5,074	100%
Average number of retail customers:				
Residential	717,665	87%	714,309	88%
Commercial	102,627	13	101,699	12
Industrial	268	-	268	-
Total	820,560	100%	816,276	100%

* Includes both energy sales to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy requirements from Electricity Service Suppliers (ESSs).

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Revenues increased $26 million, or 7%, in the second quarter of 2010 compared to the second quarter of 2009 due to an increase in Retail revenues.

Total retail revenues consists of revenues from energy sales to retail customers and deliveries to commercial and industrial customers that purchase their power from Electricity Service Suppliers (ESSs). It also includes certain accrued revenues, comprised primarily of amounts related to SB 408, the decoupling mechanism and deferrals related to the Company s RAC filings.

Total retail revenues increased $26 million, or 7%, in the second quarter of 2010 compared to the second quarter of 2009, primarily due to the net effect of the following:

A $21 million increase related to the return of a former direct access industrial customer to PGE for its energy supply in 2010 and the addition of an average of 4,300 retail customers. Residential energy deliveries increased 2.4% due largely to the impact of cooler temperatures on heating demand. While industrial energy deliveries increased 4.9%, commercial energy deliveries decreased 4.1%, primarily due to the continued impact of the slowed economy;

A $13 million increase related to SB 408. In the second quarter of 2010, the Company recorded an estimated collection from customers of $4 million, compared to an estimated refund to customers of $9 million in the second quarter of 2009;

A $5 million increase related to the decoupling mechanism. For further information on the decoupling mechanism, see Legal, Regulatory and Environmental Matters in Overview of this Item 2; and

A $16 million decrease related to a 4% decrease in average retail price, resulting primarily from a decrease in net variable power costs, partially offset by increases related to the Biglow Canyon Phase II and SWW capital projects.

Heating and cooling degree-days are an indication of the likelihood that customers will use heating and cooling, respectively, and is used to measure the effect of weather on the demand for electricity. During the second quarter of 2010, unusually cool temperatures had a somewhat offsetting impact on loads, as heating degree-days increased 49% while cooling degree-days decreased 80% compared to the second quarter of 2009. The following table indicates the number of heating and cooling degree-days for the months presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		**Cooling Degree-days**	
	2010	**2009**	**2010**	**2009**
April	413	374	-	-
May	303	175	-	34
June	145	29	18	56
2nd quarter	861	578	18	90
15-year average for the quarter	684	683	73	71

On a weather adjusted basis, energy deliveries to retail customers decreased by 3.5% in the second quarter of 2010 compared to the second quarter of 2009.

Wholesale revenues result from sales of electricity to utilities and power marketers, which are made in conjunction with the Company s effort to secure reasonably priced power for its retail customers, manage risk and administer its long-term wholesale contracts. Although such sales can vary significantly period to period, Wholesale revenues remained flat compared to the second quarter of 2009 as an 18% decrease in average price was offset by a 19% increase in wholesale energy deliveries.

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Purchased power and fuel expense increased $2 million, or 1%, in the second quarter of 2010 compared to the second quarter of 2009, with $15 million related to an 8% increase in total system load, offset by $13 million related to a 7% decrease in average variable power cost. The average variable power cost was $35.60 per MWh in the second quarter of 2010 compared to $38.12 MWh in the second quarter of 2009.

The increase in Purchased power and fuel expense consisted of the following:

A $36 million increase in the cost of generation, driven by a shift in the proportion of power provided by Company-owned generating resources, as well as a 51% increase in average cost. Thermal generation was reduced during the second quarter of 2009 as a result of the economic curtailment of Port Westward and Coyote Springs and extended maintenance outages at Colstrip and Boardman. The increase in average cost was largely due to the decrease in the relative proportion of energy received from hydro resources. In the second quarter of 2010, hydro represented 24% of total generation, compared to 46% in the second quarter of 2009; offset by

A $34 million decrease in the cost of purchased power, with an 18% decrease in total energy purchases, coupled with a 3% decrease in average cost, driven by decreases in wholesale electricity prices.

PGE s sources of energy (based in MWh) for the periods presented are as follows (MWh in thousands):

	Three Months Ended June 30,			
	2010		2009	
Generation:				
Thermal	1,397	27%	501	10%
Hydro	538	10	535	11
Wind	273	5	126	3
Total generation	2,208	42	1,162	24
Purchased power:				
Term purchases	1,362	26	2,601	54
Purchased hydro	763	15	936	19
Spot purchases	873	17	127	3
Total purchased power	2,998	58	3,664	76
Total system load	5,206	100%	4,826	100%
Less: wholesale sales	(814)		(688)	
Retail load requirement	4,392		4,138	

Although energy received under contracts from mid-Columbia projects was down 18% from the second quarter of 2009, regional hydro conditions were comparable to normal in the second quarter of 2010. While the wettest June on record in the Pacific Northwest contributed to the improvement in hydro conditions to near normal in the second quarter of 2010 from below normal in the first quarter of 2009, energy from hydro resources is expected to be below normal for 2010. The following table indicates the forecast of the April-to-September runoff (issued July 8, 2010) compared to the actual runoffs (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

Location	2010 Forecast	2009 Actual

	Runoff *	**Runoff ***
Columbia River at The Dalles, Oregon	79%	85%
Mid-Columbia River at Grand Coulee, Washington	78	80
Clackamas River at Estacada, Oregon	124	122
Deschutes River at Moody, Oregon	104	92

* Volumetric water supply forecasts 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.

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Under the PCAM, the Company can adjust future customer prices to reflect a portion of the difference between each year s forecasted NVPC included in prices (the baseline) and actual NVPC, to the extent that such difference is outside of a pre-determined deadband, subject to an earnings test. For 2010, the deadband ranges from approximately $17 million below, to $35 million above, the baseline NVPC. For the second quarter of 2010, the actual NVPC was approximately $15 million below the baseline. NVPC for the year ending December 31, 2010 is expected to be below the baseline but within the established deadband threshold; accordingly, no amount was recorded for refund to retail customers as of June 30, 2010. The actual NVPC was comparable to baseline NVPC in the second quarter of 2009.

Production and distribution expense increased $3 million, or 7%, in the second quarter of 2010 compared to the second quarter of 2009, primarily due to the net effect of the following:

- A $7 million increase related to the 2009 deferral of certain plant maintenance costs at Boardman, Beaver and Colstrip. As authorized by the OPUC in PGE s 2009 General Rate Case, certain maintenance costs that exceed those covered in current prices are deferred and amortized over ten years, beginning in 2009;
- A $2 million decrease in expenses at Boardman during the plant s shorter maintenance outage in 2010; and
- A $2 million decrease in maintenance costs at Colstrip Unit 4 and Coyote Springs.

Administrative and other expense increased $2 million, or 4%, for the second quarter of 2010 compared to the second quarter 2009, primarily due to the net effect of the following:

- A $3 million increase in legal expenses;
- A $1 million increase in pension costs due to a lower rate of return in 2010;
- A $1 million decrease in the provision for uncollectible accounts due to a reduction of accounts currently in arrears; and
- A $1 million decrease in OPUC revenue fees, which will be refunded to customers (fully offset in Retail revenues).

Depreciation and amortization expense increased $7 million, or 14%, for the second quarter of 2010 compared to the second quarter of 2009. The increase was due primarily to capital additions related to Biglow Canyon Phase II and the smart meter project.

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Other income, net decreased $9 million in the second quarter of 2010 compared to the second quarter of 2009, primarily due to the following:

- An $8 million decrease in income from non-qualified benefit plan trust assets, resulting from a $3 million loss in the fair value of the plan assets in the second quarter of 2010 compared to a $5 million gain in the second quarter of 2009; and

- A $1 million decrease in the allowance for equity funds used during construction as a result of a lower average balance of construction work in progress in 2010.

Interest expense for the second quarter of 2010 was comparable to that of the second quarter of 2009. An increase related to a higher average balance of long-term debt outstanding during the second quarter of 2010 was offset by lower interest related to reduced balances of certain regulatory liabilities.

Income taxes increased $5 million in the second quarter of 2010 compared to the second quarter of 2009, primarily due to higher income before taxes in 2010. The effective tax rate was 25% in the second quarter of 2010 compared to 10.3% in the second quarter of 2009 and differs from the federal statutory rate primarily due to benefits from federal wind production tax credits (PTCs) and state tax credits. The increase in the effective tax rate is largely the result of higher income before taxes, reducing the impact these credits had on the effective tax rate for the second quarter of 2010.

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Six Months Ended June 30, 2010 Compared to the Six Months Ended June 30, 2009

Revenues, energy deliveries (based in megawatt hours), and average number of retail customers consist of the following:

	Six Months Ended June 30,			
	2010		2009	
	Amount	% of Total	Amount	% of Total
Revenues (dollars in millions):				
Retail:				
Residential	$ 402	47%	$ 434	50%
Commercial	289	33	311	36
Industrial	104	12	81	9
Subtotal	795	92	826	95
Other - accrued revenues	11	1	(14)	(2)
Total retail revenues	806	93	812	93
Wholesale revenues	42	5	49	6
Other operating revenues	16	2	13	1
Total revenues	$ 864	100%	$ 874	100%
Energy deliveries* (MWh in thousands):				
Retail:				
Residential	3,731	36%	3,997	37%
Commercial	3,478	33	3,638	33
Industrial	1,882	18	1,889	17
Total retail energy deliveries	9,091	87	9,524	87
Wholesale energy deliveries	1,394	13	1,397	13
Total energy deliveries	10,485	100%	10,921	100%
Average number of retail customers:				
Residential	716,923	88%	714,027	88%
Commercial	101,503	12	100,356	12
Industrial	270	-	271	-
Total	818,696	100%	814,654	100%

* Includes both energy sales to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy requirements from ESSs.

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Revenues decreased $10 million, or 1%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009 as a result of the net effect of the following:

Total retail revenues decreased $6 million, or 1%, primarily due to the net effect of the following:

A $31 million decrease related to a 4% decrease in average retail price, resulting primarily from a decrease in net variable power costs, partially offset by increases for the Biglow Canyon Phase II and SWW capital projects;

A $4 million decrease related to retail energy deliveries. Residential energy deliveries decreased 7%, despite an increase in the average number of residential customers, primarily due to milder weather conditions for 2010. Commercial and industrial energy deliveries decreased 3%, largely due to the impact of continuing economic uncertainty;

A $12 million increase related to SB 408, which is included in Other - accrued revenues, resulting from an estimated $4 million customer collection recorded for the first half of 2010, compared to an estimated $8 million refund for the first half of 2009;

A $10 million increase related to the decoupling mechanism, which went into effect on February 1, 2009 and is included in Other - accrued revenues. In the first half of 2010, an estimated $8 million collection from customers was recorded, resulting from lower weather adjusted use per customer than that approved in the 2009 General Rate Case, compared to an estimated $2 million refund to customers recorded in the first half of 2009, resulting from higher weather adjusted use per customer that that approved in the 2009 General Rate Case; and

A $6 million increase resulting from a reduction in the transition adjustment credit provided to those customers electing to purchase their energy requirements from another electricity supplier. Transition adjustment credits reflect the difference between the cost and market value of PGE s power supply, as provided by Oregon s electricity restructuring law.

During the six months ended June 30, 2010, heating and cooling degree-days decreased 4% and 80%, respectively, compared to the same period of 2009. The effect of the warmer first quarter 2010, when more heating demand would have been expected, was somewhat mitigated by the cooler-than-normal second quarter. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		Cooling Degree-days	
	2010	**2009**	**2010**	**2009**
1st Quarter	1,629	2,022	-	-
2nd Quarter	861	578	18	90
Year-to-date	2,490	2,600	18	90
15-year average for the year-to-date	2,533	2,514	73	71

On a weather adjusted basis, retail energy deliveries decreased 3.4% during the six months ended June 30, 2010 compared to the six months ended June 30, 2009, with deliveries to residential customers decreasing by 3.3%. PGE projects that weather adjusted energy deliveries will decrease approximately 1% to 1.5% in 2010 relative to 2009.

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Wholesale revenues decreased $7 million, or 14%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009 due to the following:

- A $5 million decrease related to a 9% decline in average price, driven by lower natural gas and electricity prices; and

- A $2 million decrease related to a settlement and contract amendment entered into in 2010 with the City of Glendale, California.

Other operating revenues increased $3 million, or 23%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, which is due to the sale of fuel oil during 2010.

Purchased power and fuel expense decreased $29 million, or 7%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, primarily due to a 7% decrease in average variable power cost. The average variable power cost was $38.68 per MWh in the first half of 2010 compared to $41.55 per MWh in the first half of 2009.

The decrease in Purchased power and fuel expense consisted of the net effect of the following:

- A $61 million decrease in the cost of purchased power, primarily the result of an 18% decrease in total energy purchases, with the average cost of purchased power decreasing 1%; partially offset by

- A $32 million increase, primarily related to a 31% increase in thermal generation. During the first half of 2009, thermal generation was reduced due to the economic curtailment of Port Westward and Coyote Springs and extended maintenance outages at Colstrip and Boardman.

PGE s sources of energy (based in MWh) for the periods presented are as follows (MWh in thousands):

	Six Months Ended June 30,			
	2010		2009	
Generation:				
Thermal	4,115	39%	3,146	29%
Hydro	1,017	10	1,039	10
Wind	361	3	194	2
Total generation	5,493	52	4,379	41
Purchased power:				
Term purchases	2,619	25	4,241	40
Purchased hydro	1,266	12	1,616	15
Spot purchases	1,216	11	348	4
Total purchased power	5,101	48	6,205	59
Total system load	10,594	100%	10,584	100%
Less: wholesale sales	(1,394)		(1,397)	
Retail load requirement	9,200		9,187	

Regional hydro conditions were below normal in the first half of 2010, with energy received under contracts from mid-Columbia projects down 22% from the first half of 2009.

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Pursuant to the PCAM, actual NVPC was below baseline NVPC by approximately $9 million during the first half of 2010 compared to above baseline NVPC by approximately $3 million during the first half of 2009.

Production and distribution expense for the six months ended June 30, 2010 was comparable to the six months ended June 30, 2009, primarily due to the net effect of the following:

- A $7 million increase related to the deferral of certain plant maintenance costs at Boardman, Beaver and Colstrip in the first half of 2009. As authorized by the OPUC in PGE s 2009 General Rate Case, certain maintenance costs that exceed those covered in current prices are deferred and amortized over ten years, beginning in 2009;
- A $3 million decrease in maintenance costs at Colstrip Unit 4 and Coyote Springs;
- A $3 million decrease in repair and restoration expenses, related primarily to 2009 wind storms; and
- A $1 million decrease in expenses at Boardman during the plant s shorter maintenance outage in 2010.

Administrative and other expense increased $2 million, or 2%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, primarily due to the net effect of the following:

- A $4 million increase in legal expenses;
- A $1 million increase in employee benefit expenses, related primarily to increased pension costs resulting from a lower rate of return in 2010;
- A $2 million decrease in the provision for uncollectible accounts due to a reduction of accounts currently in arrears; and
- A $1 million decrease in OPUC revenue fees, which will be refunded to customers (fully offset in Retail revenues).

Depreciation and amortization expense increased $7 million, or 7%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009. A $13 million increase, related primarily to Biglow Canyon Phase II and the smart meter project, was partially offset by a $5 million decrease related to impairment losses recognized on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interests through the Net losses attributable to the noncontrolling interests. For additional information, see Note 9, Variable Interest Entities, to the Condensed Consolidated Financial Statements included in Item 1 - Financial Statements .

Other income, net decreased $3 million for the six months ended June 30, 2010 compared to the six months ended June 30, 2009. The decrease was due to lower income from non-qualified benefit plan trust assets, resulting from a $1 million loss in the fair value of the plan assets in the first half of 2010 compared to a $2 million gain in the first half of 2009.

Interest expense increased $4 million, or 8%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, primarily due to the net effect of the following:

- A $7 million increase resulting from a higher average balance of long-term debt outstanding during the first half of 2010 ($1,776 million) compared to the first half of 2009 ($1,450 million); and

A $3 million decrease related to reduced balances of certain regulatory liabilities.

Income taxes increased $2 million, or 13%, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, primarily due to higher income before taxes in 2010. The effective tax rate

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was 26.1% in the first half of 2010 compared to 24.2% in the first half of 2009 and differs from the federal statutory rate primarily due to benefits from PTCs and state tax credits. PTCs can significantly affect PGE s effective tax rate, depending on the amount of pretax income and wind generation. The increase in effective tax rate in 2010 from 2009 is largely the result of an increase in the state income tax rate and reduction in state tax credits offset by an increase in PTCs.

Net loss attributable to noncontrolling interests represents the noncontrolling interests portion of the net losses of PGE s less-than-wholly-owned subsidiaries, the majority of which consists of the impairment losses recognized on the photovoltaic solar power facilities in 2009, discussed previously in Depreciation and amortization.

Liquidity and Capital Resources

Capital Requirements

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

	2010	2011	2012	2013	2014
Ongoing capital expenditures	$ 245	$265 - $285	$230 - $250	$230 - $250	$265 - $285
Biglow Canyon Phase III	175	-	-	-	-
Hydro licensing and construction	10	$80 - $100			
Smart meter project	50	-	-	-	-
Boardman emissions controls [1]	15	$10 - $30		-	-
Total capital expenditures	$ 495[2]				
Long-term debt maturities	$ 186	$ -	$ 100	$ 100	$ 73

(1) Represents 80% of estimated total costs based on installation of nitrogen oxide and mercury controls to meet regulatory requirements. In 1985, PGE sold an undivided 15% interest in Boardman to a third party, reducing the Company s ownership interest from 80% to 65%. The purchaser has certain rights to participate in the financing of the portion of the total capital cost attributable to its interest. If the purchaser does not exercise its rights to finance the portion of the total cost attributable to its interest, PGE s share of the total cost for the emissions controls at Boardman is expected to be 80%.

(2) Amounts shown include preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

Ongoing capital expenditures - Consists of upgrades to and replacement of transmission, distribution and generation infrastructure, as well as new customer connections.

Biglow Canyon Phase III - Currently under construction, with an estimated total cost of $390 million, including $20 million of AFDC, Phase III is expected to have an installed capacity of 175 MW. Eleven turbines were in service as of June 30, 2010, with all 76 turbines expected to be placed in service by the end of the third quarter of 2010.

Hydro licensing and construction - PGE anticipates that in 2010 the FERC will issue a decision on PGE s application for a new 45-year license for the Company s four hydroelectric projects on the Clackamas River. Capital spending requirements reflected in the table above relate primarily to modifications to the projects to enhance fish passage and survival, as required by conditions contained in a 2006 settlement agreement submitted to the FERC. Pending issuance of the new license, the projects are operating under annual licenses issued by the FERC.

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Smart meter project - PGE has installed approximately 800,000 new customer smart meters as of July 30, 2010. A total of approximately 850,000 new customer meters is expected to be installed by the end of 2010. This project, which enables two-way remote communication with the Company, is expected to provide improved services, operational efficiencies, and a reduction in future operating expenses. Due to the need for communication enhancements and additional software development related to business process automation, the capital cost of this project is now estimated at $140 million to $145 million, excluding AFDC.

Boardman emissions controls

Pursuant to the Regional Haze Program and the Best Available Retrofit Technology (BART) Determination process, in June 2009, the Oregon Environmental Quality Commission (OEQC) adopted a rule that would require the installation of emissions controls at Boardman. The rule requires controls to limit:

- nitrogen oxides (NO_x), to be installed by July 1, 2011; and
- sulfur dioxide (SO_2) and particulate matter, to be installed by July 1, 2014.

The installation of these emissions controls would meet federal requirements for installing BART. PGE estimates the total cost of the NO_x controls, excluding AFDC, at approximately $28 million while the SO_2 and particulate matter controls would cost approximately $290 million.

The OEQC rule would also require the installation of Selective Catalytic Reduction (SCR) for additional NO_x control, with completion by July 1, 2017, which would meet regulatory requirements for reasonable progress towards haze emissions reduction goals. PGE estimates that the total cost of the SCR would be approximately $180 million.

In addition, under a separate rulemaking procedure with the Department of Environmental Quality (DEQ), PGE has agreed to install controls that are expected to eliminate 90 percent of the mercury emissions from the plant by 2012, to meet the requirements of the Oregon Utility Mercury Rule. Current acquisition and construction schedules should allow the Company to meet this deadline a year early at an estimated total cost of approximately $8 million.

PGE s portion of the costs associated with the NO_x controls to be installed by July 1, 2011 and the mercury controls are included in the Capital Requirements table. Due to the uncertainty with respect to both timing and scope of additional controls, as detailed in the discussion that follows, costs for those controls are not included in the table at this time.

Discussion with stakeholders in the Company s IRP process, discussed below, indicated support for the analysis of an alternative strategy regarding Boardman. Consequently, on April 12, 2010, the Company filed a petition with the OEQC requesting an amendment to the BART rules to provide for an option under which the Company would (i) install NO_x controls called for under the current BART rules by July 1, 2011, (ii) use a low sulfur coal to fire the plant s boiler and (iii) cease coal-fired operation at Boardman in 2020. The Company estimated that the cost of the NO_x controls,

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excluding AFDC, at approximately $28 million. The petition proposed ceasing coal-fired operation 20 years earlier than permitted under the existing BART rules, in consideration for eliminating the need to invest significant amounts (hundreds of millions of dollars) of capital in additional emissions controls.

On June 17, 2010, the OEQC voted to deny the Company s petition and directed the DEQ to propose alternatives through a new rulemaking. On June 28, 2010, the DEQ announced three new options for Boardman that it believes would meet federal regional haze requirements. These new options would be in addition to the option under the current BART rule that allows PGE to install controls and operate the plant through 2040.

PGE believes that the new options would require the following:

i) To control NO_x emissions, PGE would install low NO_x burners and modified over fired air ducts by 2011, and Selective Non-Catalytic Reduction controls by 2014. To reduce SO_2 emissions, PGE would most likely install a scrubber and bag house by 2014. The DEQ estimates that the total cost of these controls would be approximately $320 million. Coal-fired operations at Boardman would cease in 2020.

ii) To control NO_x emissions, PGE would install the same NO_x controls as in option i) above by 2011 and 2014. To reduce SO_2 emissions, PGE would most likely install a dry sorbent injection system by 2014. The DEQ estimates that the total cost of these controls would be approximately $100 million. No additional controls would be necessary. Coal-fired operations at Boardman would cease in December 2018.

iii) To control NO_x emissions, PGE would install only low NO_x burners and modified over fired air ducts by 2011. The DEQ estimates that the total cost of these controls would be approximately $35 million. No additional controls would be necessary. Coal-fired operations at Boardman would cease in 2015 or 2016.

PGE believes that the options proposed by the DEQ would impose greater costs, price volatility risks and power availability risks on its customers than the Company s proposal to close Boardman in 2020. PGE plans to continue to advocate for a solution that balances the interests of customers and the environment while allowing the Company sufficient time to secure replacement facilities and ensure system reliability.

It is expected that the DEQ will submit a new proposed rule to the Oregon Secretary of State by August 15, 2010. Following a public comment period during September, the DEQ plans to forward its final rulemaking package to the OEQC in November 2010, with an OEQC ruling anticipated by the end of December 2010.

IRP process

PGE submitted its 2009 IRP to the OPUC in November 2009 that proposed the acquisition of additional energy efficiency measures, the addition of wind or other renewable resources, new transmission capacity, and new natural gas-fired generation to meet both base load and peak demand. In that plan, given the options available to PGE under the current Regional Haze Rule of either installing NO_x controls required by July 1, 2011 and ceasing operation of Boardman in 2014, or installing the additional controls called for in the Regional Haze Rule and continuing operations, the Company recommended the long-term continued operation of Boardman through at least 2040 with the additional controls, as listed above under *Boardman emissions control*.

As a result of stakeholder support for an alternative plan for the operation of Boardman, on April 9, 2010, the Company filed an IRP addendum with the OPUC. The addendum seeks approval to cease coal-fired operations at Boardman in 2020, subject to certain conditions, one of which was that environmental regulatory bodies modify existing emissions rules, as discussed above.

In July 2010, the OPUC revised the timeline for review of the IRP to be more in line with the OEQC schedule for modifying the BART rules. PGE s IRP proposal and the addendum will be directly affected by the OEQC decision regarding amendments to the BART rules and the impact on the operation of Boardman.

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.

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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, 2010	2009
Cash and cash equivalents, beginning of period	$ 31	$ 10
Net cash provided by (used in):		
Operating activities	246	220
Investing activities	(245)	(396)
Financing activities	31	224
Net increase in cash and cash equivalents	32	48
Cash and cash equivalents, end of period	$ 63	$ 58

Cash Flows from Operating Activities - Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, included in net income during a given period. The $26 million increase in cash provided by operating activities in the first half of 2010 compared to the first half of 2009 was largely due to a $53 million income tax refund received and a decrease in payments made to vendors, partially offset by an increase in margin deposit requirements pursuant to power and natural gas purchase agreements. The refund of income taxes related to the carryback of 2009 tax net operating loss and production tax credits to prior years.

A significant portion of cash provided by operations consists of recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that depreciation and amortization charges will approximate $230 million in 2010. Such recovery, combined with all other sources of cash from operations, is estimated to be approximately $470 million in 2010.

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 $151 million decrease in net cash used in investing activities in the first half of 2010 compared to the first half of 2009 was due to lower capital expenditures for Biglow Canyon Phase II, partially offset by higher expenditures for Biglow Canyon Phase III. Additionally, during the first half of 2010, a $19 million distribution was made from the Nuclear decommissioning trust to PGE as a result of an OPUC order issued in connection with a deferral of Boardman power costs. For additional information, see *Regulatory Assets and Liabilities* of Note 2, Balance Sheet Components, in the Notes to Condensed Consolidated Financial Statements.

The Company plans $495 million of capital expenditures in 2010 related to Biglow Canyon Phase III, the smart meter project, hydro licensing and construction, and upgrades and replacement of transmission, distribution and generation infrastructure. See Capital Requirements section above for additional information.

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 2010, net cash provided by such activities consisted primarily of proceeds from the issuance of long-term debt of $249 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $38 million. During the first half of 2009, net cash provided by financing activities primarily consisted of proceeds received from the issuance of long-term debt of $430 million, issuance of common stock for net proceeds of $170 million, the net repayment of short-term debt of $203 million, the payment of long-term debt of $142 million and the payment of dividends of $34 million. Financing activities in the first half of 2009 also included the receipt of $7 million in capital contributions from noncontrolling interests in the solar projects.

During the first half of 2010, PGE had issued all the debt securities it expects to issue in 2010.

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 deem relevant and may include, but are not limited to, PGE s results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

Common stock dividends declared during 2010 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 17, 2010	March 25, 2010	April 15, 2010	$ 0.255
May 13, 2010	June 25, 2010	July 15, 2010	0.260
August 3, 2010	September 24, 2010	October 15, 2010	0.260

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 financial condition and credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of the credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient 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.

Short-term Debt. PGE has approval from the FERC to issue short-term debt of up to a total of $750 million through February 6, 2012 and currently has the following unsecured revolving credit facilities:

A $370 million syndicated credit facility, with $10 million and $360 million scheduled to terminate July 2012 and July 2013, respectively;

A $200 million syndicated credit facility, which is scheduled to terminate in December 2012; and

A $30 million credit facility, which is scheduled to terminate in June 2012.

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These credit facilities supplement operating cash flow and provide a primary source of liquidity. Pursuant to the individual terms of the agreements, the credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. As of June 30, 2010, PGE had no borrowings or commercial paper outstanding and had $213 million of letters of credit outstanding. As of June 30, 2010, the aggregate unused available credit under the credit facilities was $387 million.

Long-term Debt. To fund current capital expenditures and current maturities of long-term debt, PGE issued a total of approximately $249 million of long-term debt in the first half of 2010 as follows:

- On January 15th, issued $70 million of 3.46% Series First Mortgage Bonds due January 2015, with interest payable semi-annually on January 15th and July 15th;

- On March 11th, remarketed $121 million of Pollution Control Revenue Bonds at 5% due May 2033 with interest payable semi-annually on March 1st and September 1st. The Pollution Control Revenue Bonds are backed by first mortgage bonds; and

- On June 15th, issued $58 million of 3.81% Series First Mortgage Bonds due June 2017, with interest payable semi-annually on June 15th and December 15th.

Although the Company holds $21 million of repurchased Pollution Control Revenue Bonds as of June 30, 2010, which can be remarketed through 2033, no additional long-term debt is expected to be issued during the remainder of 2010.

In addition to the above long-term debt transactions, PGE repaid $149 million of 7.875% unsecured notes in the first quarter of 2010 and $37 million of 4.8% Port of St. Helens Pollution Control Revenue Bonds in the second quarter of 2010.

Capital Structure. PGE s financial objectives include the balancing of debt and equity to maintain an optimal 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 current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE s common equity ratios were 46.3% and 46.9% as of June 30, 2010 and December 31, 2009, 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	A3	A-
Senior unsecured debt	Baa2	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

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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 its wholesale, commodity and certain transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. These deposits, which are classified as Margin deposits in PGE s condensed consolidated balance sheet, are based on the contract terms and commodity prices and can vary from period to period. As of June 30, 2010, PGE had posted approximately $270 million of collateral with these counterparties, consisting of $77 million in cash and $193 million in letters of credit, $34 million of which is affiliated with master netting agreements. Based on the Company s energy portfolio, estimates of current energy market prices, and the level of collateral outstanding as of June 30, 2010, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $86 million and decreases to approximately $52 million by December 31, 2010. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $166 million at June 30, 2010 and decreases to approximately $99 million by December 31, 2010.

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.

The issuance of additional First Mortgage Bonds requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimated that on June 30, 2010 it could issue up to approximately $210 million of additional First Mortgage Bonds under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust. Future issuances would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust on the basis of property additions, bond retirements, and/or deposits of cash.

PGE s credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt ratio). As of June 30, 2010, the Company s debt ratio, as calculated under the credit agreements, was 53.7%.

Off-Balance Sheet Arrangements

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

Contractual Obligations

PGE s contractual obligations for 2010 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, 2009, filed with the SEC on February 25, 2010. Such obligations have not changed materially as of June 30, 2010, with the following exceptions:

- In January 2010, PGE issued $70 million of 3.46% First Mortgage Bonds, maturing January 2015;
- In March 2010, PGE remarketed $121 million of Pollution Control Revenue Bonds due May 2033 at 5.0%;
- In June 2010, PGE issued $58 million of 3.81% First Mortgage Bonds, maturing June 2017; and

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An increase of $44 million for new capital purchase commitments entered into, primarily related to Boardman emissions controls and turbine upgrade work at Coyote Springs, consisting of $21 million and $23 million in 2010 and 2011, respectively.

Additionally, contributions to PGE s pension plan are now estimated as follows: $30 million in 2010, $0 in 2011, $18 million in 2012, $28 million in 2013, and $23 million in 2014.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The Company is subject to various market risks which include commodity price risk, credit risk, foreign currency exchange rate risk, and interest rate 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, 2009, filed with the SEC on February 25, 2010.

Item 4. 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, 2010, these disclosure controls and procedures were effective.

There have been no changes in the Company 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, its internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings.

For information regarding legal proceedings, see PGE s 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, 2009, filed with the SEC on February 25, 2010.

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, 2009, filed with the SEC on February 25, 2010.

Item 6. Exhibits.

3.1	Second Amended and Restated Articles of Incorporation of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company s Quarterly Report on Form 10-Q filed August 3, 2009).
3.2	Seventh Amended and Restated Bylaws of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed February 19, 2010).
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

* In accordance with Regulation S-T, the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall be deemed furnished and not filed.

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.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PORTLAND GENERAL ELECTRIC COMPANY
(Registrant)

Date: August 4, 2010

By: /s/ Maria M. Pope
Maria M. Pope
Senior Vice President, Finance,

Chief Financial Officer, and Treasurer
(duly authorized officer and principal financial officer)