BALTIMORE GAS & ELECTRIC CO
Form 10-Q
August 08, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For The Quarterly Period Ended **June 30, 2011**

Commission File Number	Exact name of registrant as specified in its charter	IRS Employer Identification No.
1-12869	**CONSTELLATION ENERGY GROUP, INC.**	**52-1964611**

100 CONSTELLATION WAY, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-470-2800
(Registrant's telephone number, including area code)

1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY**	**52-0280210**

2 CENTER PLAZA, 110 WEST FAYETTE STREET, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-234-5000
(Registrant's telephone number, including area code)

MARYLAND
(State of Incorporation of both registrants)

NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrants (1) have 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, and (2) have been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether Constellation Energy Group, Inc. 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark whether Baltimore Gas and Electric Company 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark whether Constellation Energy Group, Inc. 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.
(Check one):

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether Baltimore Gas and Electric Company 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.
(Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ý (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether Constellation Energy Group, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes o No ý

Indicate by check mark whether Baltimore Gas and Electric Company is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes o No ý

Common Stock, without par value 201,321,543 shares outstanding of Constellation Energy Group, Inc. on July 29, 2011.

Baltimore Gas and Electric Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form in the reduced disclosure format.

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PART I FINANCIAL INFORMATION

Item 1 Financial Statements

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions, except per share amounts)			
Revenues				
Nonregulated revenues	**$ 2,704.7**	$ 2,559.2	**$ 5,318.6**	$ 5,077.4
Regulated electric revenues	**546.9**	651.1	**1,197.0**	1,402.4
Regulated gas revenues	**108.2**	99.6	**414.4**	416.7
Total revenues	**3,359.8**	3,309.9	**6,930.0**	6,896.5
Expenses				
Fuel and purchased energy expenses	**2,171.6**	2,267.7	**4,649.8**	4,629.8
Fuel and purchased energy expenses from affiliate	**209.3**	222.1	**404.1**	420.6
Operating expenses	**467.9**	413.7	**906.1**	810.1
Merger costs	**31.8**		**31.8**	
Depreciation, depletion, accretion, and amortization	**151.8**	125.7	**305.9**	257.6
Taxes other than income taxes	**76.5**	65.6	**154.2**	132.4
Total expenses	**3,108.9**	3,094.8	**6,451.9**	6,250.5
Equity Investment Losses	**(26.3)**	(33.5)	**(35.9)**	(54.2)
Gain on U.S. Department of Energy Settlement	**35.5**		**35.5**	
Net Gain on Divestitures		0.3		5.2
Income from Operations	**260.1**	181.9	**477.7**	597.0
Other Expense	**(15.7)**	(8.9)	**(34.7)**	(31.2)
Fixed Charges				
Interest expense	**65.2**	60.4	**136.5**	181.9
Interest capitalized and allowance for borrowed funds used during construction	**(2.2)**	(8.7)	**(4.4)**	(24.3)
Total fixed charges	**63.0**	51.7	**132.1**	157.6
Income from Continuing Operations Before Income Taxes	**181.4**	121.3	**310.9**	408.2
Income Tax Expense	**73.3**	37.5	**123.4**	133.1
Net Income	**108.1**	83.8	**187.5**	275.1
Less: Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**8.9**	11.2	**17.9**	11.0
Net Income Attributable to Common Stock	**$ 99.2**	$ 72.6	**$ 169.6**	$ 264.1
Average Shares of Common Stock Outstanding Basic	**200.1**	200.8	**199.7**	200.6
Average Shares of Common Stock Outstanding Diluted	**201.9**	202.6	**201.3**	202.2
Earnings Per Common Share Basic	**$ 0.50**	$ 0.36	**$ 0.85**	$ 1.32
Earnings Per Common Share Diluted	**$ 0.49**	$ 0.36	**$ 0.84**	$ 1.31

Dividends Declared Per Common Share	**$**	**0.24**	$	0.24	**$**	**0.48**	$	0.48

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended June 30,		***Six Months Ended June 30,***	
	2011	**2010**	**2011**	**2010**
		(In millions)		
Net Income	**$ 108.1**	$ 83.8	**$ 187.5**	$ 275.1
Other comprehensive income (OCI)				
Hedging instruments:				
Reclassification of net loss on hedging instruments from OCI to net income, net of taxes	**29.5**	179.4	**87.6**	287.9
Net unrealized (loss) gain on hedging instruments, net of taxes	**(47.4)**	70.9	**(42.0)**	(162.0)
Available-for-sale securities:				
Reclassification of net gain on sales of securities from OCI to net income, net of taxes				(0.1)
Net unrealized gain on securities, net of taxes	**0.1**		**0.1**	0.2
Defined benefit obligations:				
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes	**7.8**	4.9	**15.7**	10.8
Net unrealized gain (loss) on foreign currency, net of taxes	**0.3**	(10.7)	**1.8**	(9.0)
Other comprehensive gain (loss) equity investment in CENG, net of taxes	**1.4**	(22.1)	**14.2**	(12.2)
Other comprehensive loss other equity method investees, net of taxes		(0.3)		(0.5)
Comprehensive income	**99.8**	305.9	**264.9**	390.2
Less: Comprehensive income attributable to noncontrolling interests, net of taxes	**8.9**	11.2	**17.9**	11.0
Comprehensive Income Attributable to Common Stock	**$ 90.9**	$ 294.7	**$ 247.0**	$ 379.2

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	June 30, 2011*	December 31, 2010
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 954.8**	$ 2,028.5
Accounts receivable (net of allowance for uncollectibles of **$84.9** and $85.0, respectively)	**1,965.8**	2,059.2
Accounts receivable consolidated variable interest entities (net of allowance for uncollectibles of **$95.7** and $87.9, respectively)	**260.7**	308.9
Income taxes receivable	**81.3**	152.7
Fuel stocks	**394.1**	361.1
Materials and supplies	**136.3**	104.3
Derivative assets	**324.3**	534.4
Unamortized energy contract assets (includes **$210.4** and $400.9, respectively, related to CENG)	**335.3**	544.7
Restricted cash	**2.1**	52.0
Restricted cash consolidated variable interest entities	**46.0**	52.3
Other	**241.4**	254.5
Total current assets	**4,742.1**	6,452.6
Investments and Other Noncurrent Assets		
Investment in CENG	**2,974.9**	2,991.1
Other investments	**197.7**	189.9
Regulatory assets (net)	**370.8**	374.1
Goodwill	**180.8**	77.0
Derivative assets	**257.5**	258.9
Unamortized energy contract assets	**67.9**	109.8
Other	**302.5**	286.3
Total investments and other noncurrent assets	**4,352.1**	4,287.1
Property, Plant and Equipment		
Property, plant and equipment	**15,052.5**	13,588.9
Accumulated depreciation	**(4,433.3)**	(4,310.1)
Net property, plant and equipment	**10,619.2**	9,278.8
Total Assets	**$ 19,713.4**	$ 20,018.5

** Unaudited*
See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	*June 30, 2011**	*December 31, 2010*
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 20.6**	$ 32.4
Current portion of long-term debt	**131.5**	245.6
Current portion of long-term debt consolidated variable interest entities	**61.3**	59.7
Accounts payable	**987.0**	1,072.6
Accounts payable consolidated variable interest entities	**151.7**	189.8
Derivative liabilities	**494.2**	622.3
Unamortized energy contract liabilities	**130.9**	130.5
Deferred income taxes	**20.2**	56.5
Accrued taxes	**85.1**	71.0
Accrued expenses	**261.5**	358.1
Other	**551.6**	438.7
Total current liabilities	**2,895.6**	3,277.2
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	**2,667.6**	2,489.8
Asset retirement obligations	**33.4**	32.3
Derivative liabilities	**270.1**	353.0
Unamortized energy contract liabilities	**362.0**	411.1
Defined benefit obligations	**588.0**	574.7
Deferred investment tax credits	**25.4**	27.6
Other	**248.5**	296.0
Total deferred credits and other noncurrent liabilities	**4,195.0**	4,184.5
Long-term Debt, Net of Current Portion	**3,947.5**	4,054.2
Long-term Debt, Net of Current Portion consolidated variable interest entities	**370.8**	394.6
Equity		
Common shareholders' equity:		
Common stock	**3,265.5**	3,231.7
Retained earnings	**5,344.9**	5,270.8
Accumulated other comprehensive loss	**(595.9)**	(673.3)
Total common shareholders' equity	**8,014.5**	7,829.2
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interests	**100.0**	88.8
Total equity	**8,304.5**	8,108.0

Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 19,713.4**	$ 20,018.5

** Unaudited*
See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Six Months Ended June 30,	**2011**	**2010**
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 187.5**	$ 275.1
Adjustments to reconcile to net cash provided by (used in) operating activities		
Depreciation, depletion, accretion, and amortization	**305.9**	257.6
Amortization of energy contracts and derivatives designated as hedges	**214.5**	70.6
All other amortization	**17.9**	14.6
Deferred income taxes	**68.0**	(47.9)
Investment tax credit adjustments	**(2.2)**	(2.2)
Deferred fuel costs	**17.2**	39.0
Deferred storm costs	**(15.5)**	
Defined benefit obligation expense	**38.2**	33.7
Defined benefit obligation payments	**(19.2)**	(39.0)
Gain on divestitures		(5.2)
Gain on U. S. Department of Energy settlement	**(35.5)**	
Equity in earnings of affiliates less than dividends received	**40.2**	69.7
Derivative contracts classified as financing activities	**6.7**	79.8
Changes in:		
Accounts receivable, excluding margin	**(20.5)**	21.1
Derivative assets and liabilities, excluding collateral	**323.9**	227.3
Net collateral and margin	**(46.7)**	(73.4)
Materials, supplies, and fuel stocks	**(11.5)**	(44.2)
Other current assets	**127.9**	49.8
Accounts payable	**(158.4)**	(29.9)
Liability for unrecognized tax benefits	**3.7**	(26.0)
Accrued taxes and other current liabilities	**(6.2)**	(1,084.9)
Other	**(59.4)**	7.8
Net cash provided by (used in) operating activities	**976.5**	(206.6)
Cash Flows From Investing Activities		
Investments in property, plant and equipment	**(566.3)**	(425.0)
Asset and business acquisitions, net of cash acquired	**(1,229.6)**	(372.9)
Proceeds from U.S. Department of Energy grant	**28.3**	
Proceeds from sales of investments and other assets		21.2
Proceeds from investment tax credits and grants related to renewable energy investments	**37.3**	21.5
Payment for issuance of loans receivable	**(15.0)**	
Contract and portfolio acquisitions	**(3.7)**	(29.0)
Decrease (increase) in restricted funds	**57.9**	(30.0)
Other	**(9.0)**	(0.7)
Net cash used in investing activities	**(1,700.1)**	(814.9)
Cash Flows From Financing Activities		
Net repayment of short-term borrowings	**(11.8)**	(17.0)
Proceeds from issuance of common stock	**11.3**	8.8
Proceeds from issuance of long-term debt	**7.5**	

Repayment of long-term debt	**(251.2)**	(629.0)
Debt and credit facility costs	**(3.2)**	(0.7)
Common stock dividends paid	**(91.9)**	(92.6)
BGE preference stock dividends paid	**(6.6)**	(6.6)
Proceeds from contract and portfolio acquisitions	**1.0**	2.3
Derivative contracts classified as financing activities	**(6.7)**	(79.8)
Other	**1.5**	(0.7)
Net cash used in financing activities	**(350.1)**	(815.3)
Net Decrease in Cash and Cash Equivalents	**(1,073.7)**	(1,836.8)
Cash and Cash Equivalents at Beginning of Period	**2,028.5**	3,440.0
Cash and Cash Equivalents at End of Period	**$ 954.8**	$ 1,603.2

See Notes to Consolidated Financial Statements
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Revenues				
Electric revenues	**$ 547.1**	$ 651.1	**$ 1,197.3**	$ 1,402.4
Gas revenues	**109.1**	100.4	**416.4**	418.4
Total revenues	**656.2**	751.5	**1,613.7**	1,820.8
Expenses				
Operating expenses				
Electricity purchased for resale	**199.5**	286.8	**496.7**	636.4
Electricity purchased for resale from affiliate	**73.2**	114.6	**129.9**	238.6
Gas purchased for resale	**49.8**	42.1	**220.9**	236.6
Operations and maintenance	**130.1**	118.6	**250.7**	239.1
Operations and maintenance from affiliate	**28.5**	27.9	**60.9**	56.4
Merger costs	**9.2**		**9.2**	
Depreciation and amortization	**66.8**	60.6	**143.1**	128.3
Taxes other than income taxes	**46.4**	45.0	**96.2**	92.6
Total expenses	**603.5**	695.6	**1,407.6**	1,628.0
Income from Operations	**52.7**	55.9	**206.1**	192.8
Other Income	**6.1**	5.5	**12.2**	12.0
Fixed Charges				
Interest expense	**33.1**	33.9	**66.6**	68.3
Allowance for borrowed funds used during construction	**(1.6)**	(1.5)	**(3.3)**	(2.8)
Total fixed charges	**31.5**	32.4	**63.3**	65.5
Income Before Income Taxes	**27.3**	29.0	**155.0**	139.3
Income Taxes	**10.7**	12.0	**57.3**	57.9
Net Income	**16.6**	17.0	**97.7**	81.4
Preference Stock Dividends	**3.3**	3.3	**6.6**	6.6
Net Income Attributable to Common Stock	**$ 13.3**	$ 13.7	**$ 91.1**	$ 74.8

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	June 30, 2011*	December 31, 2010
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 120.6**	$ 50.0
Accounts receivable (net of allowance for uncollectibles of **$33.9** and $34.9, respectively)	**328.8**	351.4
Accounts receivable, unbilled (net of allowance for uncollectibles of **$1.0** and $1.0, respectively)	**173.4**	268.8
Accounts receivable, affiliated companies	**2.1**	1.1
Income taxes receivable, net		55.9
Fuel stocks	**51.4**	66.5
Materials and supplies	**39.6**	31.2
Prepaid taxes other than income taxes	**2.3**	51.7
Regulatory assets (net)	**85.2**	78.7
Restricted cash consolidated variable interest entity	**25.2**	29.5
Other	**7.2**	9.5
Total current assets	**835.8**	994.3
Investments and Other Assets		
Regulatory assets (net)	**370.8**	374.1
Receivable, affiliated company	**476.2**	494.3
Other	**48.4**	52.2
Total investments and other assets	**895.4**	920.6
Utility Plant		
Plant in service		
Electric	**5,287.9**	5,127.9
Gas	**1,353.8**	1,323.0
Common	**436.0**	507.8
Total plant in service	**7,077.7**	6,958.7
Accumulated depreciation	**(2,441.7)**	(2,449.3)
Net plant in service	**4,636.0**	4,509.4
Construction work in progress	**290.8**	232.9
Plant held for future use	**10.2**	10.1
Net utility plant	**4,937.0**	4,752.4

Total Assets	**$**	**6,668.2**	$	6,667.3

** Unaudited*
See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	June 30, **2011***	*December 31,* **2010**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 131.5**	$ 22.0
Current portion of long-term debt consolidated variable interest entity	**61.3**	59.7
Accounts payable	**215.1**	252.9
Accounts payable, affiliated companies	**69.3**	84.9
Customer deposits	**80.0**	78.9
Deferred income taxes	**32.1**	30.1
Accrued taxes	**39.2**	19.0
Liability for uncertain tax positions	**58.7**	62.8
Accrued expenses and other	**92.0**	99.7
Total current liabilities	**779.2**	710.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,420.9**	1,354.9
Payable, affiliated company	**255.1**	250.8
Deferred investment tax credits	**7.9**	8.4
Other	**16.6**	20.1
Total deferred credits and other liabilities	**1,700.5**	1,634.2
Long-term Debt		
Rate stabilization bonds consolidated variable interest entity	**424.7**	454.4
Other long-term debt	**1,431.5**	1,431.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(1.9)**	(2.0)
Current portion of long-term debt	**(131.5)**	(22.0)
Current portion of long-term debt consolidated variable interest entity	**(61.3)**	(59.7)
Total long-term debt	**1,919.2**	2,059.9
Equity		
Common shareholder's equity	**2,079.3**	2,073.2
Preference stock not subject to mandatory redemption	**190.0**	190.0
Total equity	**2,269.3**	2,263.2
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 6,668.2**	$ 6,667.3

** Unaudited*
See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Six Months Ended June 30,	**2011**	**2010**
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 97.7**	$ 81.4
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**143.1**	128.3
Other amortization	**3.6**	1.6
Deferred income taxes	**59.7**	55.2
Investment tax credit adjustments	**(0.5)**	(0.5)
Deferred fuel costs	**17.2**	39.0
Deferred storm costs	**(15.5)**	
Defined benefit plan expenses	**20.3**	17.4
Allowance for equity funds used during construction	**(7.0)**	(5.2)
Changes in:		
Accounts receivable	**115.0**	16.0
Accounts receivable, affiliated companies	**(1.0)**	12.9
Materials, supplies, and fuel stocks	**6.7**	22.9
Income tax receivable, net	**55.9**	
Other current assets	**28.0**	49.9
Accounts payable	**(37.8)**	(7.8)
Accounts payable, affiliated companies	**(15.6)**	(24.5)
Other current liabilities	**13.8**	(119.8)
Long-term receivables and payables, affiliated companies	**2.1**	(13.9)
Regulatory assets, net	**(11.4)**	(18.8)
Other	**(7.8)**	(52.9)
Net cash provided by operating activities	**466.5**	181.2
Cash Flows From Investing Activities		
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(304.5)**	(190.3)
Proceeds from U.S. Department of Energy grant	**28.3**	
Change in cash pool at parent		314.7
Proceeds from sales of investments and other assets		20.9
Decrease in restricted funds	**4.3**	0.8
Net cash (used in) provided by investing activities	**(271.9)**	146.1
Cash Flows From Financing Activities		
Repayment of long-term debt	**(29.7)**	(28.1)
Repayment of short-term borrowings		(46.0)
Credit facility costs	**(2.7)**	
Preference stock dividends paid	**(6.6)**	(6.6)
Distribution to parent	**(85.0)**	
Net cash used in financing activities	**(124.0)**	(80.7)
Net Increase in Cash and Cash Equivalents	**70.6**	246.6
Cash and Cash Equivalents at Beginning of Period	**50.0**	13.6

Cash and Cash Equivalents at End of Period	**$ 120.6**	$ 260.2

See Notes to Consolidated Financial Statements.
Certain prior-period amounts have been reclassified to conform with the current period's presentation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Basis of Presentation

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy Group, Inc. (Constellation Energy) and Baltimore Gas and Electric Company (BGE). References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Various factors can have a significant impact on our results for interim periods. This means that the results for this quarter are not necessarily indicative of future quarters or full year results given the seasonality of our business.

Our interim financial statements on the previous pages reflect all adjustments that management believes are necessary for the fair statement of the results of operations for the interim periods presented. These adjustments are of a normal recurring nature.

Reclassifications

We made the following reclassifications:

- We have separately presented "Liability for unrecognized tax benefits" that was previously presented within "Other" on our Consolidated Statements of Cash Flows.
- We have separately presented "Regulatory assets, net" that was previously presented within "Other" on BGE's Consolidated Statements of Cash Flows.

Pending Merger with Exelon Corporation

On April 28, 2011, Constellation Energy entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon.

The merger agreement contains certain termination rights for both Constellation Energy and Exelon. Under specified circumstances Constellation Energy may be required to pay Exelon a termination fee of $200 million and Exelon may be required to pay Constellation Energy a termination fee of $800 million.

In connection with the proposed merger, Exelon and Constellation Energy announced several commitments, each of which is contingent upon completion of the merger, that they included in their filing for approval of the merger with the Maryland Public Service Commission (Maryland PSC). The estimated value of the commitments, including a proposed rate rebate of $100 per residential BGE customer, is approximately $250 million.

The merger agreement has been approved by both companies' boards of directors, but completion of the merger is contingent upon, among other things, the approval of the transaction by stockholders of both companies and receipt of required regulatory approvals, including the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, the Maryland PSC and several other state and federal regulatory bodies. The parties are working to complete the merger early in 2012.

During the quarter and six months ended June 30, 2011, we incurred $31. 8 million pre-tax in costs related to our pending merger with Exelon.

Variable Interest Entities

As of June 30, 2011, we consolidate four variable interest entities (VIEs) for which we are the primary beneficiary, and we have significant interests in six other VIEs for which we do not have controlling financial interests. We discuss our VIEs in more detail in *Note 4* of our 2010 Annual Report on Form 10-K.

Consolidated Variable Interest Entities

Our, and BGE's, consolidated VIEs consist of:

- RSB BondCo LLC (BondCo), a special purpose bankruptcy-remote limited liability company formed by BGE to acquire, hold, and to issue and service bonds secured by rate stabilization property,
- a retail gas group formed to enter into a collateralized gas supply agreement with a third party gas supplier,
- a retail power supply company, and
- a group of solar project limited liability companies formed to build, own, and operate solar power facilities. While we own 100% of these entities, we determined that the individual solar project entities are VIEs because either the entities require additional subordinated financial support in the form of loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or renewable energy credits purchase agreements. We are the primary beneficiary of the solar project entities because we control the design, construction, and operation of the solar power facilities.

We further discuss how we determine whether we are the primary beneficiary of VIEs in more detail in *Note 4* of our 2010 Annual Report on Form 10-K.

For each of our consolidated VIEs:

- The assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE. In the case of BondCo, BGE is required to remit all payments it receives from customers for rate

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stabilization charges to BondCo. During the quarter and six months ended June 30, 2011, BGE remitted $15.9 million and $38.5 million, respectively, to BondCo. During the quarter and six months ended June 30, 2010, BGE remitted $18.2 million and $42.0 million, respectively, to BondCo.

- Except for providing capital funding to the solar entities for ongoing construction of the solar power facilities and a $75 million parental guarantee to the third party gas supplier in support of the retail gas group, during the quarter and six months ended June 30, 2011, neither we nor BGE:
  - provided any additional financial support to the VIEs, and
  - had any contractual commitments or obligations to provide financial support to the VIEs.
- The creditors of the VIEs do not have recourse to our or BGE's general credit.

We include the consolidated VIEs in our consolidated financial statements at June 30, 2011 and December 31, 2010 as follows:

	June 30, 2011	December 31, 2010
	(In millions)	
Current assets	$ 455.4	$ 516.6
Noncurrent assets	50.9	57.7
Total Assets	$ 506.3	$ 574.3
Current liabilities	$ 282.8	$ 345.5
Noncurrent liabilities	376.3	399.0
Total Liabilities	$ 659.1	$ 744.5

Unconsolidated Variable Interest Entities

As of June 30, 2011 and December 31, 2010, we had significant interests in six VIEs for which we were not the primary beneficiary. We have not provided any material financial or other support to these entities during the quarter and six months ended June 30, 2011 and we do not intend to provide any additional financial or other support to these entities in the future.

The following tables present summary information about these entities:

As of June 30, 2011	**Power Contract Monetization VIEs**	**All Other VIEs**	**Total**
		(In millions)	
Total assets	$ 393.2	$ 323.1	$ 716.3
Total liabilities	310.6	123.0	433.6
Our ownership interest		56.1	56.1
Other ownership interests	82.6	144.0	226.6
Our maximum exposure to loss:			
Letters of credit	20.5		20.5
Carrying amount of our investment Other investments		48.9	48.9
Debt and payment guarantees		5.0	5.0

As of December 31, 2010	**Total**

	Power Contract Monetization VIEs	All Other VIEs	
	(In millions)		
Total assets	$ 492.9	$ 288.3	$ 781.2
Total liabilities	382.6	113.2	495.8
Our ownership interest		48.7	48.7
Other ownership interests	110.3	126.4	236.7
Our maximum exposure to loss:			
Letters of credit	24.9		24.9
Carrying amount of our investment Other investments		41.4	41.4
Debt and payment guarantees		5.0	5.0

We assess the risk of a loss equal to our maximum exposure to be remote. In addition, there are no agreements with, or commitments by, third parties that would affect the fair value or risk of our variable interests in these VIEs.

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Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing net income attributable to common stock by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Our dilutive common stock equivalent shares consist of stock options and other stock-based compensation awards. The following table presents stock options that were not dilutive and were excluded from the computation of diluted EPS in each period, as well as the dilutive common stock equivalent shares:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Non-dilutive stock options	**4.2**	4.4	**5.6**	4.4
Dilutive common stock equivalent shares	**1.8**	1.8	**1.6**	1.6

Acquisitions

MXenergy Holdings Inc.

In July 2011, we acquired all of the outstanding stock of MXenergy Holdings Inc. (MXenergy), a retail energy marketer of natural gas and electric power to residential and commercial customers, for approximately $175 million, subject to certain purchase price adjustments. MXenergy serves approximately 540,000 customers in several markets across the United States and Canada. We will account for this acquisition as a business combination within our NewEnergy business segment. We will include MXenergy's results of operations in our consolidated financial statements as of the date of acquisition.

Star Electricity, Inc.

In May 2011, we acquired all of the outstanding stock of Star Electricity, Inc. (StarTex), a retail electric provider, for $163.5 million in cash, all of which was paid at closing. StarTex serves approximately 170,000 customers in the Texas residential market.

We recorded the acquisition as follows:

At May 27, 2011

	(In millions)
Cash and cash equivalents	$ 17.9
Other current assets	42.2
Goodwill[1]	100.9
Acquired contracts and intangibles[1 2]	78.3
Other assets	1.2
Total assets acquired	240.5
Total liabilities	(77.0)
Net assets acquired	$ 163.5

1 None is deductible for tax purposes.
2 The weighted average amortization for these assets is approximately 3 years.

The preliminary net assets acquired are based on estimates, the resolution of which could impact the final net assets acquired.

We have included StarTex's results of operations in our consolidated financial statements as part of our NewEnergy business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the quarters and six months ended June 30, 2011 and 2010 and to our financial condition as of December 31, 2010.

Boston Generating

In January 2011, we acquired Boston Generating's 2,950 MW fleet of generating plants for cash of $1.1 billion. The fleet acquired includes the following four natural gas power plants and one fuel oil plant located in the Boston, Massachusetts area:

- Mystic 7 574 MW,
- Mystic 8 and 9 1,580 MW,
- Fore River 787 MW, and
- Mystic Jet, a fuel oil plant 9 MW.

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We recorded the acquisition as follows:

At January 3, 2011

		(In millions)
Current assets	$	92.2
Land		29.2
Property, plant and equipment		1,061.8
Noncurrent assets		0.1
Total assets acquired		1,183.3
Current liabilities		(77.5)
Noncurrent liabilities		(21.8)
Total liabilities		(99.3)
Net assets acquired	$	1,084.0

We have included the results of operations from these plants in our consolidated financial statements as part of our Generation business segment since the date of acquisition.

The proforma impact of this acquisition would not have been material to our results of operations for the quarters and six months ended June 30, 2011 and 2010 and to our financial condition as of June 30, 2011 and December 31, 2010.

Divestitures

Constellation Energy Partners LLC

In June 2011, we agreed to sell all of our interests in Constellation Energy Partners LLC (CEP) to PostRock Energy Corporation (PostRock). Under the terms of that agreement, PostRock would receive all of our voting rights, including our right to appoint two of the five members of CEP's board of directors. In return, we would receive cash, PostRock common stock and warrants to acquire additional shares of PostRock common stock at a premium to the market price at the closing of the transaction. At the date of this filing, we are discussing with PostRock potential modifications to the transaction. We expect this transaction to close in 2011.

Quail Run Energy Center

In December 2010, we signed an agreement to sell our Quail Run Energy Center (Quail Run), a 550 MW natural gas plant in west Texas, to High Plains Diversified Energy Corporation (HPDEC). This agreement was contingent upon HPDEC obtaining financing through the sale of municipal bonds.

In June 2011, we terminated the agreement to sell Quail Run based on the buyer's inability to satisfy all of the conditions for the sale.

Gain on U.S. Department of Energy Settlement

On June 30, 2011, CENG executed a settlement agreement with the United States Department of Energy (DOE) under which Constellation Energy will receive payment of $35.5 million related to costs incurred through October 31, 2008 to store spent nuclear fuel at the Calvert Cliffs nuclear power plant. The settlement also details a framework and procedure for recovery of damages incurred or to be incurred through the end of 2013. The agreement settles a lawsuit that sought to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel at the Calvert Cliffs nuclear power plant. We discuss our lawsuit involving CENG's nuclear plants in more detail in our *2010 Annual Report on Form 10-K*.

As part of the 2009 agreement between Constellation Energy and EDF in which Constellation Energy sold a 49.99% interest in CENG to EDF, Constellation Energy retained the right to receive payments from any settlement with the DOE that related to periods prior to the formation of the joint venture on November 6, 2009. As such, Constellation Energy recognized a pre-tax gain in the second quarter of 2011 for

$35.5 million and we expect to receive the funds in the third quarter of 2011.

The lawsuits relating to the storage of spent nuclear fuel at the Ginna and Nine Mile Point nuclear power plants remain outstanding.

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Investment in Constellation Energy Nuclear Group, LLC (CENG)

We own a 50.01% interest in CENG, a nuclear generation and operation business. Our total equity in earnings of our investment in CENG is as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
		(In millions)		
CENG	**$ 14.9**	$ 40.2	**$ 27.6**	$ 63.6
Amortization of basis difference in CENG	**(39.9)**	(61.5)	**(69.2)**	(104.2)
Total equity investment losses CENG[1]	**$ (25.0)**	$ (21.3)	**$ (41.6)**	$ (40.6)

1 For the quarters ended June 30, 2011 and 2010, total equity investment earnings (losses) in CENG include $0.5 million and $0.5 million, respectively, of expense related to the portion of cost of certain share-based awards that we fund on behalf of EDF Group and affiliates (EDF). For the six months ended June 30, 2011 and 2010, total equity investment earnings (losses) in CENG include $0.9 million and $1.6 million, respectively, of expense related to the portion of cost of certain share-based awards that we fund on behalf of EDF.

The basis difference is the difference between the carrying amount of our investment in CENG and our share of the underlying equity in CENG, because the underlying assets of CENG were retained at their historical carrying value. See *Note 2* to our 2010 Annual Report on Form 10-K for a more detailed discussion.

Summarized income statement information for CENG for the quarters and six months ended June 30, 2011 and 2010 is as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
		(In millions)		
Revenues	**$ 354.5**	$ 376.1	**$ 713.1**	$ 737.0
Expenses	**333.8**	302.9	**675.2**	626.2
Income from operations	**20.7**	73.2	**37.9**	110.8
Net income	**30.9**	81.3	**57.1**	130.4

Regulatory Assets (net)

In March 2011, the Maryland PSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $18.9 million of costs as regulatory assets. These costs will be recovered over a 5-year period beginning December 2010 and relate to the deferral of:

- $15.8 million of storm costs incurred in February 2010,
- $2.7 million of electric deferred income tax expense recognized in 2010 relating to the elimination of the tax exempt status of drug subsidies provided to companies under Medicare Part D after December 31, 2012, and
- $0.4 million of electric workforce reduction costs incurred in 2010.

The regulatory assets for the storm costs and the workforce reduction costs will earn a regulated rate of return.

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Information by Operating Segment

Our reportable operating segments are Generation, NewEnergy, Regulated Electric, and Regulated Gas. We discuss our reportable operating segments in detail in *Note 3* of our 2010 Annual Report on Form 10-K.

These reportable segments are strategic businesses based principally upon regulations, products, and services that require different technologies and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. A summary of information by operating segment is shown in the table below.

	Reportable Segments				Holding Company and Other	Eliminations	Consolidated
	Generation	NewEnergy	Regulated Electric	Regulated Gas			
				(In millions)			
Quarter ended June 30,							
2011							
Unaffiliated revenues	**$ 256.4**	**$ 2,447.8**	**$ 546.9**	**$ 108.2**	**$ 0.5**	**$**	**$ 3,359.8**
Intersegment revenues	**420.1**	**112.0**	**0.2**	**0.9**		**(533.2)**	
Total revenues	**676.5**	**2,559.8**	**547.1**	**109.1**	**0.5**	**(533.2)**	**3,359.8**
Net income (loss)	**40.9**	**51.7**	**22.9**	**(6.3)**	**(1.1)**		**108.1**
Net income (loss) attributable to common stock	**40.9**	**46.1**	**20.5**	**(7.2)**	**(1.1)**		**99.2**
2010							
Unaffiliated revenues	$ 283.0	$ 2,276.1	$ 651.1	$ 99.6	$ 0.1	$	$ 3,309.9
Intersegment revenues	267.3	114.7		0.8		(382.8)	
Total revenues	550.3	2,390.8	651.1	100.4	0.1	(382.8)	3,309.9
Net income (loss)	15.3	50.8	20.9	(3.9)	0.7		83.8
Net income (loss) attributable to common stock	15.3	42.9	18.4	(4.7)	0.7		72.6
Six months ended June 30,							
2011							
Unaffiliated revenues	**$ 515.9**	**$ 4,802.7**	**$ 1,197.0**	**$ 414.4**	**$**	**$**	**$ 6,930.0**
Intersegment revenues	**828.2**	**169.2**	**0.3**	**2.0**		**(999.7)**	
Total revenues	**1,344.1**	**4,971.9**	**1,197.3**	**416.4**		**(999.7)**	**6,930.0**
Net income (loss)	**53.7**	**40.3**	**62.6**	**35.1**	**(4.2)**		**187.5**
Net income (loss) attributable to common stock	**53.7**	**29.0**	**57.7**	**33.4**	**(4.2)**		**169.6**
2010							
Unaffiliated revenues	$ 574.2	$ 4,503.1	$ 1,402.4	$ 416.7	$ 0.1	$	$ 6,896.5
Intersegment revenues	556.0	238.6		1.7		(796.3)	
Total revenues	1,130.2	4,741.7	1,402.4	418.4	0.1	(796.3)	6,896.5
Net income (loss)	42.4	154.9	48.1	33.3	(3.6)		275.1
Net income (loss) attributable to common stock	42.4	150.5	43.0	31.8	(3.6)		264.1

Our Generation business operating results for the quarter and six months ended June 30, 2011 include the following after-tax items:

- *amortization of basis difference in investment in CENG of $24.0 million and $41.6 million, respectively,*
- *impact of power purchase agreement with CENG of $30.3 million and $57.3 million, respectively, (amount represents the amortization of our "unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its "unamortized energy contract liability"),*
- *gain on settlement with DOE for storage of spent nuclear fuel of $21.3 million and $21.3 million, respectively,*
-

transaction fees incurred related to our acquisition of Boston Generating's 2,950 MW fleet of generating plants in Massachusetts of $0.1 million and $10.1 million, respectively, and

- *costs incurred related to our pending merger with Exelon of $9.5 million and $9.5 million, respectively.*

Our NewEnergy business operating results for the quarter and six months ended June 30, 2011 include the amortization of credit facility amendment fees in connection with the 2009 EDF transaction of $1.5 million and $3.0 million, respectively, and costs incurred relating to our pending merger with Exelon of $4.3 million and $4.3 million, respectively.

Our Regulated Electric business operating results for the quarter and six months ended June 30, 2011 include costs incurred relating to our pending merger with Exelon of $4.1 million and $4.1 million, respectively. BGE will not seek recovery of these costs in rates.

Our Regulated Gas business operating results for the quarter and six months ended June 30, 2011 include costs incurred relating to our pending merger with Exelon of $1.4 million and $1.4 million, respectively. BGE will not seek recovery of these costs in rates.

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Pension and Postretirement Benefits

We show the components of net periodic pension benefit cost in the following table:

	Quarter Ended June 30,				Six Months Ended June 30,			
		2011		**2010**		**2011**		**2010**
				(In millions)				
Components of net periodic pension benefit cost								
Service cost	**$**	**15.0**	$	9.1	**$**	**26.4**	$	18.6
Interest cost		**24.6**		19.7		**47.2**		41.4
Expected return on plan assets		**(32.3)**		(23.2)		**(62.3)**		(49.9)
Recognized net actuarial loss		**11.9**		8.7		**24.1**		16.8
Amortization of prior service cost		**1.1**		0.9		**2.1**		1.9
Amount capitalized as construction cost		**(3.2)**		(2.9)		**(6.1)**		(4.8)
Net periodic pension benefit cost[1]	**$**	**17.1**	$	12.3	**$**	**31.4**	$	24.0

1 BGE's portion of our net periodic pension benefit cost, excluding amounts capitalized, was $9.0 million for the quarter ended June 30, 2011 and $8.5 million for the quarter ended June 30, 2010. BGE's portion of our net periodic pension benefit cost, excluding amounts capitalized, was $18.1 million for the six months ended June 30, 2011 and $14.8 million for the six months ended June 30, 2010. Net periodic pension benefit costs exclude settlement charges of $1.5 million in the quarter and six months ended June 30, 2010.

We show the components of net periodic postretirement benefit cost in the following table:

	Quarter Ended June 30,				Six Months Ended June 30,			
		2011		**2010**		**2011**		**2010**
				(In millions)				
Components of net periodic postretirement benefit cost								
Service cost	**$**	**0.8**	$	0.6	**$**	**1.5**	$	1.3
Interest cost		**5.1**		5.0		**9.3**		9.7
Amortization of transition obligation		**0.5**		0.6		**1.0**		1.1
Recognized net actuarial loss (gain)		**0.2**		(0.1)		**0.8**		0.2
Amortization of prior service cost		**(0.9)**		(0.7)		**(1.5)**		(1.4)
Amount capitalized as construction cost		**(1.7)**		(1.6)		**(3.1)**		(2.9)
Net periodic postretirement benefit cost[1]	**$**	**4.0**	$	3.8	**$**	**8.0**	$	8.0

1 BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $4.9 million for the quarter ended June 30, 2011 and $4.6 million for the quarter ended June 30, 2010. BGE's portion of our net periodic postretirement benefit costs, excluding amounts capitalized, was $9.5 million for the six months ended June 30, 2011 and $9.4 million for the six months ended June 30, 2010.

Our non-qualified pension plans and our postretirement benefit programs are not funded; however, we have trust assets securing certain executive pension benefits. We estimate that we will incur approximately $9.4 million in pension benefit payments for our non-qualified pension plans and approximately $22.6 million for retiree health and life insurance costs in 2011.

Financing Activities

Credit Facilities and Short-term Borrowings

We discuss the purposes for and the types of instruments used for entering into credit facilities and short-term borrowings in *Note 8* of our 2010 Annual Report on Form 10-K.

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Constellation Energy

Constellation Energy had bank lines of credit under committed credit facilities totaling $4.2 billion at June 30, 2011 for short-term financial needs, primarily for our NewEnergy business, as follows:

Type of Credit Facility	Amount (In billions)	Expiration Date	Capacity Type
Syndicated Revolver	$ 2.50	October 2013	Letters of credit and cash
Commodity-linked	0.50	August 2014	Letter of credit and cash
Bilateral	0.55	September 2014	Letters of credit
Bilateral	0.25	December 2014	Letters of credit and cash
Bilateral	0.25	June 2014	Letters of credit and cash
Bilateral	0.15	September 2013	Letters of credit
Total	$ 4.20		

At June 30, 2011, we had approximately $1.4 billion in letters of credit issued, including $0.3 billion in letters of credit issued under the commodity-linked credit facility, and no commercial paper outstanding under these facilities. The commodity-linked facility capacity increases as natural gas price levels decrease compared to a reference price that is adjusted periodically. As of June 30, 2011, this facility's capacity was $0.3 billion.

In July 2011, a subsidiary of Constellation Energy entered into a three-year senior secured credit facility that is designed to support the growth of our solar operations. The amount committed under the facility is $150 million, which may be increased up to $200 million at the subsidiary's request with additional commitments by the lenders. At closing, we borrowed $130.0 million. Borrowings incur interest at a variable rate payable quarterly and are secured by the equity interests in the subsidiary and the entities that own the solar projects as well as the assets of the subsidiary and each project entity. The obligations of our subsidiary are guaranteed by Constellation Energy and the project entities. The Constellation Energy guaranty will terminate upon the subsidiary obtaining a stand-alone investment grade credit rating or the satisfaction of a number of conditions, at which time the financing will become nonrecourse to Constellation Energy. We discuss the accounting treatment for our solar operations in more detail on page 9.

Also, in July 2011, we amended and extended our existing reserve based lending facility that supports our upstream gas operations. The borrowing base committed under the facility was increased to $150 million and can grow up to a total of $500 million if the assets support a higher borrowing base and we are able to obtain additional commitments from lenders. The facility now expires in July 2016. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Constellation Energy in the event of a default. At closing, we borrowed $74.0 million under the facility with interest payable quarterly. The facility includes a provision that requires our entities that own the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one.

In July 2011, a subsidiary of Constellation Energy entered into a $40 million nonrecourse project financing to fund construction of our 30MW solar facility in Sacramento, California. Borrowings will incur interest at a variable rate, payable quarterly, and are secured by the equity interests and assets of the subsidiary. The construction borrowings will convert into a 19-year variable rate note upon commercial operation of the facility. Construction is expected to be completed by December 2011. The subsidiary also executed interest rate swaps for a notional amount of $30 million in order to convert the variable interest payments to fixed payments on the $40 million facility amount.

In addition to this facility, this subsidiary entered into a treasury grant bridge loan for $26 million and an equity bridge loan for $28 million. Both loans will be utilized to fund construction and must be repaid shortly after commercial operations of the solar facility.

At June 30, 2011, Constellation Energy had $20.6 million of short-term notes outstanding with a weighted average effective interest rate of 6.54%.

BGE

As of June 30, 2011, BGE has a $600.0 million revolving credit facility expiring in March 2015. BGE can borrow directly from the banks, use the facility to allow commercial paper to be issued, if available, or issue letters of credit. At June 30, 2011, BGE had no commercial paper or direct borrowings outstanding. There were immaterial letters of credit outstanding at June 30, 2011. As of July 31, 2011, BGE had $30.0 million of commercial paper outstanding.

Debt

In January 2011, we redeemed $213.5 million of our 7.00% Notes, which represented the remaining outstanding 7.00% Notes due April 1, 2012, pursuant to a notice to redeem that was issued in December 2010. We redeemed these notes with part of the proceeds from the $550 million 5.15% Notes issued in December 2010, terminated certain interest rate swaps and recognized a pre-tax loss of approximately $5 million on this transaction. We discuss the termination of the interest rate swaps in our *Derivative Instruments* note.

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Net Available Liquidity

The following table provides a summary of our, and BGE's, net available liquidity at June 30, 2011:

At June 30, 2011	***Constellation Energy (excluding BGE)***	***BGE***
	(In billions)	
Credit facilities[1]	$ 3.7	$ 0.6
Less: Letters of credit issued[1]	(1.1)	
Less: Cash drawn on credit facilities		
Undrawn facilities	2.6	0.6
Less: Commercial paper outstanding		
Net available facilities	2.6	0.6
Add: Cash and cash equivalents[2]	0.8	0.1
Less: Reserved cash[3]	(0.2)	
Net available liquidity	$ 3.2	$ 0.7

1 Excludes $0.5 billion commodity-linked credit facility due to its contingent nature and $0.3 billion in letters of credit posted against it.

2 BGE's cash balance at June 30, 2011 was $120.6 million.

3 Represents cash used in July 2011 to acquire MXenergy. See Acquisitions note for more detail.

Credit Facility Compliance and Covenants

The credit facilities of Constellation Energy and BGE contain a material adverse change representation but draws on the facilities are not conditioned upon Constellation Energy and BGE making this representation at the time of the draw. However, to the extent a material adverse change has occurred and prevents Constellation Energy or BGE from making other representations that are required at the time of the draw, the draw would be prohibited.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2011, the debt to capitalization ratio as defined in the credit agreements was 33%.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2011, the debt to capitalization ratio for BGE as defined in this credit agreement was 43%.

Decreases in Constellation Energy's or BGE's credit ratings would not trigger an early payment on any of our, or BGE's, credit facilities. However, the impact of a credit ratings downgrade on our financial ratios associated with our credit facility covenants would depend on our financial condition at the time of such a downgrade and on the source of funds used to satisfy the incremental collateral obligation resulting from a credit ratings downgrade. For example, if we were to use existing cash balances to fund the cash portion of any additional collateral obligations resulting from a credit ratings downgrade, we would not expect a material impact on our financial ratios. However, if we were to issue long-term debt or use our credit facilities to fund any additional collateral obligations, our financial ratios could be materially affected. Failure by Constellation Energy, or BGE, to comply with these covenants could result in the acceleration of the maturity of the borrowings outstanding and preclude us from issuing letters of credit under these facilities.

Income Taxes

We compute the income tax expense for each quarter based on the estimated annual effective tax rate for the year. The effective tax rate was 40.4% and 39.7% for the quarter and six months ended June 30, 2011, respectively, compared to 30.9% and 32.6% for the same periods of 2010. The higher effective tax rates for the quarter and six months ended June 30, 2011 are primarily due to lower deductions for qualified production activities and higher expense associated with uncertain tax positions and increased state income taxes, resulting from increased business activity in unitary states and changes in the Illinois and Michigan tax laws.

The BGE effective tax rate was 39.2% and 37.0% for the quarter and six months ended June 30, 2011, respectively, compared to 41.4% and 41.6% for the same periods of 2010. The lower effective tax rates for 2011 are primarily due to the partial reversal during the quarter ended March 31, 2011 of the unfavorable tax adjustment recorded in the quarter ended March 31, 2010 to reflect the impact on our regulated electric business of the healthcare reform legislation that eliminated the tax exempt status of prescription drug subsidies received under Medicare Part D. The partial reversal in 2011 resulted from the Maryland PSC's authorization for BGE to create an electric regulatory asset for this tax law change and amortize the balance over a five-year period as provided in its March 2011 comprehensive order in BGE's most recent base rate case.

Income tax expense for both Constellation Energy and BGE for the quarter and six months ended June 30, 2011 reflects a deferred tax benefit for the costs incurred associated with our pending merger with Exelon. The ultimate treatment of these costs for tax purposes will be determined at the time the merger is closed or terminated. We discuss our pending merger with Exelon on page 9.

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Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2011 and our total unrecognized tax benefits at June 30, 2011:

At June 30, 2011

	(In millions)
Total unrecognized tax benefits, January 1, 2011	$ 239.8
Increases in tax positions related to the current year	1.4
Increases in tax positions related to prior years	4.1
Reductions in tax positions related to prior years	(8.7)
Total unrecognized tax benefits, June 30, 2011[1]	$ 236.6

1 BGE's portion of our total unrecognized tax benefits at June 30, 2011 was $66.3 million.

If the total amount of unrecognized tax benefits of $236.6 million were ultimately realized, our income tax expense would decrease by approximately $170 million. The $170 million includes state tax refund claims of $55.9 million that have been disallowed by tax authorities and are subject to appeals.

It is reasonably possible that unrecognized tax benefits could decrease within the next year by approximately $66 million primarily as a result of an expected settlement with the IRS regarding BGE's change of accounting method for tax purposes with respect to certain transmission and distribution expenditures. This decrease is not expected to have a material impact on BGE's financial condition or results of operation.

Interest and penalties recorded in our Consolidated Statements of Income as tax expense relating to liabilities for unrecognized tax benefits were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Interest and penalties recorded as tax expense (benefit)	**$ 2.7**	$ (10.7)	**$ 5.5**	$ (7.3)

BGE's portion of interest and penalties was immaterial for both periods presented.

Accrued interest and penalties recognized in our Consolidated Balance Sheets were $22.3 million, of which BGE's portion was $5.0 million, at June 30, 2011, and $16.8 million, of which BGE's portion was $3.8 million, at December 31, 2010.

Taxes Other Than Income Taxes

Taxes other than income taxes primarily include property and gross receipts taxes along with franchise taxes and other non-income taxes, surcharges, and fees.

BGE and our NewEnergy operations collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer and others are imposed on BGE and our NewEnergy business. Where these taxes, such as sales taxes, are imposed on the customer, we account for these taxes on a net basis with no impact to our Consolidated Statements of Income. However, where these taxes, such as gross receipts taxes or other surcharges or fees, are imposed on BGE or our NewEnergy business, we account for these taxes on a gross basis. Accordingly, we recognize revenues for these taxes collected from customers along with an offsetting tax expense, which are both included in our and BGE's Consolidated Statements of Income. The taxes, surcharges, or fees that are included in revenues were as follows:

Quarter Ended June 30,	Six Months Ended June 30,

	2011	2010	2011	2010
	(In millions)			
Constellation Energy (including BGE)	**$ 35.5**	$ 30.5	**$ 70.2**	$ 61.5
BGE	**19.6**	19.3	**42.6**	41.2

Guarantees

Our guarantees do not represent incremental Constellation Energy obligations; rather they primarily represent parental guarantees of subsidiary obligations. The following table summarizes the maximum exposure by guarantor based on the stated limit of our outstanding guarantees:

At June 30, 2011	**Stated Limit**
	(In billions)
Constellation Energy guarantees	$ 9.3
BGE guarantees	0.3
Total guarantees	$ 9.6

At June 30, 2011, Constellation Energy had a total of $9.6 billion in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below.

- Constellation Energy guaranteed a face amount of $9.3 billion as follows:
  - $8.8 billion on behalf of our Generation and NewEnergy businesses to allow them the

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flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was approximately $1.5 billion at June 30, 2011, which represents the total amount the parent company could be required to fund based on June 30, 2011 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets.

- $0.5 billion primarily on behalf of CENG's nuclear generating facilities for nuclear insurance and credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants. We recorded the fair value of $11.1 million for these guarantees on our Consolidated Balance Sheets.

- BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II.

Commitments and Contingencies

We have made substantial commitments in connection with our Generation, NewEnergy, regulated electric and gas, and other nonregulated businesses. These commitments relate to:

- purchase of electric generating capacity and energy as well as renewable energy credits,
- procurement and delivery of fuels,
- the capacity and transmission and transportation rights for the physical delivery of power and gas to meet our obligations to our customers, and
- service agreements, capital for construction programs, and other.

Our Generation and NewEnergy businesses enter into various contracts for the procurement and delivery of fuels primarily related to supplying our generating plant requirements. In most cases, our contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. These contracts expire in various years between 2011 and 2030. In addition, our Generation and NewEnergy businesses enter into contracts for the purchase of energy, capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2011 and 2023.

Our Generation and NewEnergy businesses also have committed to service agreements and other purchase commitments for our plants.

Our regulated electric business enters into various contracts for the procurement of electricity. These contracts expire between 2011 and 2013 and represent BGE's estimated requirements to serve residential and small commercial customers as follows:

Contract Duration	***Percentage of Estimated Requirements***
From July 1, 2011 to May 2012	100%
From June 2012 to September 2012	75
From October 2012 to May 2013	50
From June 2013 to September 2013	25

The cost of power under these contracts is recoverable under the Provider of Last Resort agreement reached with the Maryland PSC.

Our regulated gas business enters into various contracts for the procurement, transportation, and storage of gas. Our regulated gas business has gas procurement contracts that expire in 2011 and transportation and storage contracts that expire between 2012 and 2027. The cost of gas under these contracts is recoverable under BGE's gas cost adjustment clause discussed in *Note 1* of our 2010 Annual Report on Form 10-K.

We have also committed to service agreements and other obligations related to our information technology systems.

At June 30, 2011, the total amount of commitments was $7.0 billion. These commitments are primarily related to our Generation and NewEnergy businesses.

Long-Term Power Sales Contracts

We enter into long-term power sales contracts in connection with our load-serving activities. We also enter into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2031 and provide for the sale of energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power producing facilities, including renewable energy, extend for terms into 2033 and provide for the sale of all or a portion of the actual output of certain of our power producing facilities. Substantially all long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

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Contingencies

Litigation

In the normal course of business, we are involved in various legal proceedings. We discuss the significant matters below.

Merger with Exelon

In late April and early May 2011, shortly after Constellation Energy and Exelon announced their agreement to merge the two companies, twelve shareholder class action lawsuits were filed in the Circuit Court for Baltimore City in Maryland. Each class action suit was filed on behalf of a proposed class of the shareholders of Constellation Energy against Constellation Energy, members of Constellation Energy's board of directors, and Exelon. The shareholder class actions generally allege that the individual directors breached their fiduciary duties by entering into the proposed merger because they failed to maximize the value that the shareholders would receive from the merger, and failed to disclose adequately all material information relating to the proposed merger. The class actions also allege that Constellation Energy and Exelon aided and abetted the individual directors' breaches of their fiduciary duties. The lawsuits challenge the proposed merger, seek to enjoin a shareholder vote on the proposed merger until all material information is provided relating to the proposed merger, and ask for rescission of the proposed merger and any related transactions that have been completed as of the date that the court grants any relief. The class action lawsuits also seek certification as class actions, compensatory damages, costs and disbursements related to the action, including attorneys' and experts' fees, and rescission damages. Plaintiffs in three of the twelve lawsuits subsequently filed motions to consolidate all the lawsuits. The court has granted the motion to consolidate and all actions are now proceeding as a single lawsuit. Given that these lawsuits were recently filed, that the court has not certified any class and the plaintiffs have not quantified their potential damage claims, we are unable at this time to provide an estimate of the range of possible loss relating to these proceedings or to determine the ultimate outcome of these lawsuits or their possible effect on our, or BGE's, financial results or their possible effect on the pending merger with Exelon.

Securities Class Action

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation Energy between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation Energy, a number of its present or former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation Energy's June 27, 2008 offering of Debentures. The securities class actions also allege that Constellation Energy issued false or misleading statements or was aware of material undisclosed information which contradicted public statements including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions seek, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. On August 13, 2010, the District Court of Maryland issued a ruling on the motion to dismiss, holding that the plaintiffs failed to state a claim with respect to the claims of the common shareholders under the Securities Act of 1934 and restricting the suit to those persons who purchased Debentures in the June 2008 offering. Given that the discovery phase has just begun, that the court has not certified any class and the plaintiffs have not quantified their potential damage claims relating to the June 2008 offering, we are unable at this time to provide an estimate of the range of possible loss relating to these proceedings or to determine the ultimate outcome of the securities class actions or their possible effect on our, or BGE's financial results.

Mercury

Since September 2002, BGE, Constellation Energy, and several other defendants have been involved in numerous actions filed in the Circuit Court for Baltimore City, Maryland alleging mercury poisoning from several sources, including coal plants formerly owned by BGE. The plants are now owned by a subsidiary of Constellation Energy. In addition to BGE and Constellation Energy, approximately 11 other defendants, consisting of pharmaceutical

companies, manufacturers of vaccines, and manufacturers of Thimerosal have been sued. Approximately 70 cases, involving claims related to approximately 132 children, have been filed to date, with each claimant seeking $20 million in compensatory damages, plus punitive damages, from us.

The claims against BGE and Constellation Energy have been dismissed in all of the cases either with prejudice based on rulings by the Court or without prejudice based on voluntary dismissals by the plaintiffs' counsel. Plaintiffs may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. We believe that we have meritorious defenses and intend to defend any appeals vigorously. We are unable to provide an estimate of the range of possible loss relating to these cases given that only limited discovery occurred in these cases prior to the dismissals being granted and, as a result, we cannot predict the outcome of these cases, or their possible effect on our, or BGE's, financial results.

Asbestos

Since 1993, BGE and certain Constellation Energy subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Constellation Energy knew of and exposed individuals to an asbestos hazard. In addition to BGE and Constellation Energy, numerous other parties are defendants in these cases.

Approximately 477 individuals who were never employees of BGE or Constellation Energy have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third party claims brought by other defendants may also be filed against BGE and Constellation Energy in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or Constellation Energy and a small minority of these cases have been resolved for amounts that were not material to our financial results.

Discovery begins in these cases once they are placed on the trial docket. At present, only a small number of our pending cases have reached the trial docket. Given the limited discovery, BGE and Constellation Energy do not know the specific facts that we believe are necessary for us to provide an estimate of the possible loss relating to these claims. The specific facts we do not know include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors,
- the names of the plaintiffs' employers,
- the dates on which and the places where the exposure allegedly occurred, and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Environmental Matters

Solid and Hazardous Waste

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, which is its list of sites targeted for clean-up and enforcement, and sent a general notice letter to BGE and 19 other parties identifying them as potentially responsible parties at the site. In March 2004, we and other potentially responsible parties formed the 68th Street Coalition and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the EPA and 19 of the potentially responsible parties, including BGE, with respect to investigation of the site became effective. The settlement requires the potentially responsible parties, over the course of several years, to identify contamination at the site and recommend clean-up options. BGE is indemnified by a wholly owned subsidiary of Constellation Energy for most of the costs related to this settlement and clean-up of the site. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the EPA are still subject to EPA review, we believe that the range of estimated clean-up costs to be allocated among all of the potentially responsible parties will be between approximately $50 million and $64 million depending on the clean-up option selected by the EPA. The EPA is expected to make a final selection of one of the alternatives in 2012. As the alternative to be selected by the EPA and the allocation of the clean-up costs among the potentially responsible parties is not yet known, we cannot provide an estimate of the range of our possible loss.

Air Quality

In January 2009, the EPA issued a notice of violation (NOV) to a subsidiary of Constellation Energy, as well as to the other owners and the operator of the Keystone coal-fired power plant in Shelocta, Pennsylvania. We hold a 20.99% interest in the Keystone plant. The NOV alleges that the plant performed various capital projects beginning in 1984 without complying with the new source review permitting requirements of the Clean Air Act. The EPA also contends that the alleged failure to comply with those requirements are continuing violations under the plant's air

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permits. The EPA could seek civil penalties under the Clean Air Act for the alleged violations.

The owners and operator of the Keystone plant have investigated the allegations and had a meeting with the EPA where they provided the EPA with both legal and factual documentation to support their position that no violations have occurred. Since that time, the EPA has not requested any further meeting or otherwise acted on the allegations. We believe there are meritorious defenses to the allegations contained in the NOV. Because there are significant facts in dispute and this matter is only in the NOV stage, at this time we cannot estimate the range of possible loss or predict whether a proceeding will be commenced.

Water Quality

In October 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the Environment relating to groundwater contamination at a third party facility that was licensed to accept fly ash, a byproduct generated by our coal-fired plants. The consent decree requires the payment of a $1.0 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. We recorded a liability in our Consolidated Balance Sheets of approximately $10.6 million, which includes the $1 million penalty and our estimate of probable costs to remediate contamination, replace drinking water supplies, monitor groundwater conditions, and otherwise comply with the consent decree. We have paid approximately $7.2 million of these costs as of June 30, 2011, resulting in a remaining liability at June 30, 2011 of $3.4 million. We estimate that it is reasonably possible that we could incur additional costs of up to approximately $10 million more than the liability that we accrued.

In April 2007, PennEnvironment and the Sierra Club brought a Clean Water Act citizen suit against the operator of the Conemaugh power plant in Pennsylvania, seeking civil penalties and injunctive relief for alleged violations of Conemaugh's water permit. Throughout the relevant time period, the operator of the Conemaugh plant has been working closely with the Pennsylvania Department of Environmental Protection (PADEP) to ensure that the facility operates in an environmentally sound manner, and does not cause any adverse environmental impacts. Pursuant to a consent order between PADEP and the operator, a variety of studies have been conducted and treatment facilities have been designed and have been built or are pending construction, all in order to comply with the stringent limits set out in Conemaugh's water permit. On March 21, 2011, the court entered a partial summary judgment in the plaintiffs' favor, declaring as a matter of law that discharges from the Conemaugh plant had violated the water permit. In June 2011, the parties agreed to settle the proceeding for an immaterial amount.

Insurance

We discuss our non-nuclear insurance programs in *Note 12* of our 2010 Annual Report on Form 10-K.

Derivative Instruments

Risks, Objectives, and Strategies

Substantially all of our risk management activities involving derivatives occur in our competitive businesses. In carrying out our competitive business activities, we purchase and sell power, fuel, and other energy-related commodities in competitive markets. These activities expose us to significant risks, including market risk from price volatility for energy commodities and the credit risks of counterparties with which we enter into contracts.

To lower our exposure to the risk of unfavorable fluctuations in commodity prices, interest rates, and foreign currency rates, we routinely enter into derivative contracts, such as fixed price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges, for hedging purposes. We also enter into derivative contracts for trading purposes.

We discuss the nature of our business and associated risks in connection with our objectives and strategies for using derivatives for both risk management and non-risk management activities in *Note 13* of our 2010 Annual Report on Form 10-K.

Accounting for Derivative Instruments

We recognize all qualifying derivative instruments on the balance sheet at fair value as either assets or liabilities.

Accounting Designation

We must evaluate new and existing transactions and agreements to determine whether they meet the definition of a derivative, for which there are several possible accounting treatments. The permissible accounting treatments include:

- normal purchase normal sale (NPNS),
- cash flow hedge,
- fair value hedge, and
- mark-to-market.

Mark-to-market is required as the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

We discuss our accounting policies for derivatives and hedging activities and their impacts on our financial statements in *Note 1* to our 2010 Annual Report on Form 10-K.

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In the sections below, we describe the significant activity in 2011 by accounting treatment.

NPNS

We continue to elect NPNS accounting for certain contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business.

Cash Flow Hedging

Commodity Cash Flow Hedges

We have designated fixed-price forward contracts as cash-flow hedges of forecasted purchases and sales of energy, fuel, and other related commodities for the years 2011 through 2017. We had net unrealized pre-tax losses on these cash-flow hedges recorded in "Accumulated other comprehensive loss" of $312.5 million at June 30, 2011 and $388.0 million at December 31, 2010.

We expect to reclassify $156.8 million of net pre-tax losses on cash-flow hedges from "Accumulated other comprehensive loss" into earnings during the next twelve months based on market prices at June 30, 2011. However, the actual amount reclassified into earnings could vary from the amounts recorded at June 30, 2011, due to future changes in market prices.

When we determine that a forecasted transaction originally designated as a hedged item has become probable of not occurring, we immediately reclassify net unrealized gains or losses associated with those hedges from "Accumulated other comprehensive loss" to earnings. We recognized in earnings the following pre-tax amounts on such contracts:

	Quarter Ended June 30,		**Six Months Ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Pre-tax gains (losses)	**$ (0.3)**	$ 1.1	**$ (0.3)**	$ (0.3)

Interest Rate Swaps Designated as Cash Flow Hedges

Accumulated other comprehensive loss includes net unrealized pre-tax gains on interest rate cash-flow hedges of prior debt issuances totaling $8.8 million at June 30, 2011 and $10.1 million at December 31, 2010. We expect to reclassify $0.1 million of pre-tax net gains on these cash-flow hedges from "Accumulated other comprehensive loss" into "Interest expense" during the next twelve months. We had no hedge ineffectiveness on these swaps.

Fair Value Hedging

We elect fair value hedge accounting for a limited portion of our derivative contracts including certain interest rate swaps and certain forward contracts and swaps associated with natural gas fuel in storage. The objectives for electing fair value hedge accounting in these situations are to manage our exposure to changes in the fair value of our assets and liabilities, to optimize the mix of our fixed and floating-rate debt, and to hedge the value of our natural gas in storage.

Interest Rate Swaps Designated as Fair Value Hedges

At December 31, 2010, we had interest rate swaps qualifying as fair value hedges relating to $400 million of our fixed-rate debt maturing in 2012 and 2015. The fair value of these hedges was an unrealized gain of $35.7 million at December 31, 2010.

At June 30, 2011, we have interest rate swaps qualifying as fair value hedges relating to $550 million of our fixed-rate debt maturing in 2015, and converted this notional amount of debt to floating-rate. The fair value of these hedges was an unrealized gain of $35.3 million at June 30, 2011.

We recorded the fair value of these hedges as an increase in our "Derivative assets" and an increase in our "Long-term debt."

Hedge Ineffectiveness

For all categories of derivative instruments designated in hedging relationships, we recorded in earnings the following pre-tax gains (losses) related to hedge ineffectiveness:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
		(In millions)		
Cash-flow hedges	**$ (5.9)**	$ (37.6)	**$ (22.8)**	$ (24.3)
Fair value hedges	**(1.9)**		**(1.8)**	
Total	**$ (7.8)**	$ (37.6)	**$ (24.6)**	$ (24.3)

The ineffectiveness in the table above excludes a pre-tax gain of $1.1 million related to the change in our fair value hedges excluded from hedge ineffectiveness for the quarter and six months ended June 30, 2011. We did not recognize any gain or loss related to the change in our fair value hedges excluded from hedge ineffectiveness during the quarter and six months ended June 30, 2010.

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Mark-to-Market

During February 2011, we entered into interest rate swaps through 2015 related to $150 million of our fixed rate debt maturing in 2020, and converted this notional amount of debt to floating rate over the related time frame. However, these interest rate swaps do not qualify as fair value hedges and will be marked to market through earnings.

Quantitative Information About Derivatives and Hedging Activities

Balance Sheet Tables

We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis, including cash collateral, whenever we have a legally enforceable master netting agreement with a counterparty to a derivative contract. We use master netting agreements whenever possible to manage and substantially reduce our potential counterparty credit risk. The net presentation in our Consolidated Balance Sheets reflects our actual credit exposure after giving effect to the beneficial effects of these agreements and cash collateral, and our credit risk is reduced further by other forms of collateral.

The following tables provide information about the risks we manage using derivatives. These tables only include derivatives and do not reflect the price risks we are hedging that arise from physical assets or nonderivative accrual contracts within our Generation and NewEnergy businesses.

We present this information by disaggregating our net derivative assets and liabilities into gross components on a contract-by-contract basis before giving effect to the risk-reducing benefits of master netting arrangements and collateral. As a result, we must present each individual contract as an "asset value" if it is in the money or a "liability value" if it is out of the money, regardless of whether the individual contracts offset market or credit risks of other contracts in full or in part. Therefore, the gross amounts in these tables do not reflect our actual economic or credit risk associated with derivatives. This gross presentation is intended only to show separately the various derivative contract types we use, such as commodities, interest rate, and foreign exchange.

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The contracts in the tables below are segregated between derivatives designated for hedge accounting and those not designated for hedge accounting. Derivatives not designated in hedging relationships include our NewEnergy retail operations, economic hedges of accrual activities, and risk management and trading activities. We use the end of period accounting designation to determine the classification for each derivative position.

As of June 30, 2011	**Derivatives Designated as Hedging Instruments for Accounting Purposes**		**Derivatives Not Designated As Hedging Instruments for Accounting Purposes**		**All Derivatives Combined**	
Contract type	**Asset Values[3]**	**Liability Values[4]**	**Asset Values[3]**	**Liability Values[4]**	**Asset Values[3]**	**Liability Values[4]**
			(In millions)			
Power contracts	$ 1,018.7	$ (1,037.6)	$ 4,573.0	$ (4,977.8)	$ 5,591.7	$ (6,015.4)
Gas contracts	1,405.9	(1,432.1)	2,682.9	(2,516.5)	4,088.8	(3,948.6)
Coal contracts	55.0	(32.0)	154.7	(142.8)	209.7	(174.8)
Other commodity contracts[1]			305.9	(299.8)	305.9	(299.8)
Interest rate contracts	35.3		40.7	(37.9)	76.0	(37.9)
Foreign exchange contracts			13.7	(8.2)	13.7	(8.2)
Total gross fair values	$ 2,514.9	$ (2,501.7)	$ 7,770.9	$ (7,983.0)	$ 10,285.8	$ (10,484.7)
Netting arrangements[5]					(9,717.9)	9,717.9
Cash collateral					(58.8)	2.5
Net fair values					$ 509.1	$ (764.3)
Net fair value by balance sheet line item:						
Accounts receivable[2]					$ (72.7)	
Derivative assets current					324.3	
Derivative assets noncurrent					257.5	
Derivative liabilities current						(494.2)
Derivative liabilities noncurrent						(270.1)
Total Derivatives					$ 509.1	$ (764.3)

1 Other commodity contracts include oil, freight, emission allowances, and weather contracts.

2 Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.

3 Represents in-the-money contracts without regard to potentially offsetting out-of-the-money contracts under master netting agreements.

4 Represents out-of-the-money contracts without regard to potentially offsetting in-the-money contracts under master netting agreements.

5 Represents the effect of legally enforceable master netting agreements.

As of December 31, 2010	Derivatives Designated as Hedging Instruments for Accounting Purposes		Derivatives Not Designated As Hedging Instruments for Accounting Purposes		All Derivatives Combined	
Contract type	**Asset Values[3]**	**Liability Values[4]**	**Asset Values[3]**	**Liability Values[4]**	**Asset Values[3]**	**Liability Values[4]**
			(In millions)			
Power contracts	$ 1,167.9	$ (1,362.8)	$ 6,795.0	$ (7,166.5)	$ 7,962.9	$ (8,529.3)
Gas contracts	1,902.3	(1,832.8)	3,390.1	(3,155.3)	5,292.4	(4,988.1)
Coal contracts	97.0	(48.6)	266.0	(259.7)	363.0	(308.3)
Other commodity contracts[1]			61.4	(61.6)	61.4	(61.6)
Interest rate contracts	35.7		34.4	(35.7)	70.1	(35.7)
Foreign exchange contracts			11.0	(8.4)	11.0	(8.4)
Total gross fair values	$ 3,202.9	$ (3,244.2)	$ 10,557.9	$ (10,687.2)	$ 13,760.8	$ (13,931.4)
Netting arrangements[5]					(12,955.5)	12,955.5
Cash collateral					(28.4)	0.6
Net fair values					$ 776.9	$ (975.3)
Net fair value by balance sheet line item:						
Accounts receivable[2]					$ (16.4)	
Derivative assets current					534.4	
Derivative assets noncurrent					258.9	
Derivative liabilities current						(622.3)
Derivative liabilities noncurrent						(353.0)
Total Derivatives					$ 776.9	$ (975.3)

1 Other commodity contracts include oil, freight, emission allowances, and weather contracts.

2 Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.

3 Represents in-the-money contracts without regard to potentially offsetting out-of-the-money contracts under master netting agreements.

4 Represents out-of-the-money contracts without regard to potentially offsetting in-the-money contracts under master netting agreements.

5 Represents the effect of legally enforceable master netting agreements.

Gain and (Loss) Tables

The tables below summarize derivative gains and losses segregated into the following categories:

- cash flow hedges,
- fair value hedges, and
- mark-to-market derivatives.

The tables only include this information for derivatives and do not reflect the related gains or losses that arise from generation and generation-related assets, nonderivative accrual contracts, or NPNS contracts within our Generation and NewEnergy businesses, other than fair value hedges, for which we separately show the gain or loss on the hedged asset or liability. As a result, these tables only reflect the impact of derivatives themselves and therefore do not necessarily include all of the income statement impacts of the transactions for which derivatives are used to manage risk. For a more complete discussion of how derivatives affect our financial performance, see our accounting policy for *Revenues, Fuel and Purchased Energy Expenses, and Derivatives and Hedging Activities* in *Note 1* of our 2010 Annual Report on Form 10-K.

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The following tables present gains and losses on derivatives designated as cash flow hedges.

Cash Flow Hedges				***Quarter Ended June 30,***			
	Gain (Loss) Recorded in AOCI			**Gain (Loss) Reclassified from AOCI into Earnings**		**Ineffectiveness Gain (Loss) Recorded in Earnings**	
Contract type:	**2011**	**2010**	**Statement of Income (Loss) Line Item**	**2011**	**2010**	**2011**	**2010**
			(In millions)				
Hedges of forecasted sales:			Nonregulated revenues				
Power contracts	$ (32.4)	$ (80.8)		$ 23.3	$ (1.0)	$ 56.2	$ (20.5)
Gas contracts	49.7	1.8		73.1	16.2	(51.2)	(2.9)
Coal contracts							
Other commodity contracts[1]							
Foreign exchange contracts							
Total gains (losses)	$ 17.3	$ (79.0)	Total included in nonregulated revenues	$ 96.4	$ 15.2	$ 5.0	$ (23.4)
Hedges of forecasted purchases:			Fuel and purchased energy expense				
Power contracts	$ (14.9)	$ 163.9		$ (133.3)	$ (331.6)	$ (6.8)	$ (3.4)
Gas contracts	(67.2)	(2.6)		(10.6)	45.1	(5.2)	(13.1)
Coal contracts	(8.8)	32.6		2.1	(15.3)	1.1	2.3
Other commodity contracts[2]							
Foreign exchange contracts							
Total (losses) gains	$ (90.9)	$ 193.9	Total included in fuel and purchased energy expense	$ (141.8)	$ (301.8)	$ (10.9)	$ (14.2)
Hedges of interest rates:			Interest expense				
Interest rate contracts					0.2		
Total gains	$	$	Total included in interest expense	$	$ 0.2	$	$
Grand total (losses) gains	$ (73.6)	$ 114.9		$ (45.4)	$ (286.4)	$ (5.9)	$ (37.6)

1 Other commodity sale contracts include oil and freight contracts.

2 Other commodity purchase contracts include freight and emission allowances.

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Cash Flow Hedges				*Six Months Ended June 30,*			
	Gain (Loss) Recorded in AOCI		**Statement of Income (Loss) Line Item**	**Gain (Loss) Reclassified from AOCI into Earnings**		**Ineffectiveness Gain (Loss) Recorded in Earnings**	
Contract type:	**2011**	**2010**		**2011**	**2010**	**2011**	**2010**
			(In millions)				
Hedges of forecasted sales:			Nonregulated revenues				
Power contracts	$ (55.8)	$ 121.7		$ 5.0	$ (60.2)	$ 57.4	$ 1.3
Gas contracts	60.8	(33.1)		95.3	36.4	(49.0)	(4.0)
Coal contracts							
Other commodity contracts[1]					(0.7)		
Foreign exchange contracts							
Total gains (losses)	$ 5.0	$ 88.6	Total included in nonregulated revenues	$ 100.3	$ (24.5)	$ 8.4	$ (2.7)
Hedges of forecasted purchases:			Fuel and purchased energy expense				
Power contracts	$ 2.6	$ (291.6)		$ (232.1)	$ (534.7)	$ (19.1)	$ (12.7)
Gas contracts	(69.1)	(76.2)		(17.9)	123.1	(12.9)	(13.1)
Coal contracts	(3.4)	21.8		9.4	(27.8)	0.8	4.0
Other commodity contracts[2]		(0.2)			(0.3)		0.2
Foreign exchange contracts							
Total losses	$ (69.9)	$ (346.2)	Total included in fuel and purchased energy expense	$ (240.6)	$ (439.7)	$ (31.2)	$ (21.6)
Hedges of interest rates:			Interest expense				
Interest rate contracts				1.1	4.1		
Total gains	$	$	Total included in interest expense	$ 1.1	$ 4.1	$	$
Grand total (losses) gains	$ (64.9)	$ (257.6)		$ (139.2)	$ (460.1)	$ (22.8)	$ (24.3)

1 Other commodity sale contracts include oil and freight contracts.

2 Other commodity purchase contracts include freight and emission allowances.

The following table presents gains and losses on derivatives designated as fair value hedges and, separately, the gains and losses on the hedged item.

Fair Value Hedges	*Quarter Ended June 30,*		*Six Months Ended June 30,*	
	Amount of Gain (Loss) Recognized in Income on Derivative	**Amount of Gain (Loss) Recognized in Income on Hedged Item**	**Amount of Gain (Loss) Recognized in Income on Derivative**	**Amount of Gain (Loss) Recognized in Income on Hedged Item**

Contract type:	**Statement of Income (Loss) Line Item**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
					(In millions)				
Commodity contracts:									
Gas contracts	Nonregulated revenues	$ 0.8	$	$	$	$ 0.8	$	$	$
Interest rate contracts	Interest expense	14.4	4.2	(16.0)	(4.1)	16.4	17.4	(17.5)	(15.2)
Total gains (losses)		$ 15.2	$ 4.2	$ (16.0)	$ (4.1)	$ 17.2	$ 17.4	$ (17.5)	$ (15.2)

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The following table presents gains and losses on mark-to-market derivatives.

Mark-to-Market Derivatives		**Quarter Ended June 30,**		**Six Months Ended June 30,**	
		Amount of Gain (Loss) Recorded in Income on Derivative		**Amount of Gain (Loss) Recorded in Income on Derivative**	
Contract type:	**Statement of Income (Loss) Line Item**	**2011**	**2010**	**2011**	**2010**
		(In millions)			
Commodity contracts:					
Power contracts	Nonregulated revenues	$ 15.9	$ 40.1	$ 39.2	$ (24.8)
Gas contracts	Nonregulated revenues	8.5	5.0	19.7	30.7
Coal contracts	Nonregulated revenues	7.9	7.6	(0.7)	7.7
Other commodity contracts[1]	Nonregulated revenues	7.3	(3.8)	(9.3)	1.1
Coal contracts	Fuel and purchased energy expense				
Interest rate contracts	Nonregulated revenues	0.1	(0.6)	(0.6)	(1.7)
Interest rate contracts	Interest expense	3.3		3.3	
Foreign exchange contracts	Nonregulated revenues	5.3	(1.2)	(6.7)	(2.1)
Total gains (losses)		$ 48.3	$ 47.1	$ 44.9	$ 10.9

1 Other commodity contracts include oil, freight, uranium, weather, and emission allowances.

Volume of Derivative Activity

The volume of our derivatives activity is directly related to the fundamental nature and scope of our business and the risks we manage. We own or control electric generating facilities, which exposes us to both power and fuel price risk; we serve electric and gas wholesale and retail customers within our NewEnergy business, which exposes us to electricity and natural gas price risk; and we provide risk management services and engage in trading activities, which can expose us to a variety of commodity price risks. In order to manage the risks associated with these activities, we are required to be an active participant in the energy markets, and we routinely employ derivative instruments to conduct our business.

Derivative instruments provide an efficient and effective way to conduct our business and to manage the associated risks. As such, we use derivatives in the following ways:

- We manage our generating resources and NewEnergy business based upon established policies and limits, and we use derivatives to establish a portion of our hedges and to adjust the level of our hedges from time to time.
- We engage in trading activities which enable us to execute hedging transactions in a cost-effective manner. We manage those activities based upon various risk measures, including position limits, economic value at risk (EVaR) and value at risk (VaR), and we use derivatives to establish and maintain those activities within the prescribed limits.
- We also use derivatives to execute, control, and reduce the overall level of our trading positions and risk as well as to manage a portion of our interest rate risk associated with debt and our foreign currency risk from non-dollar denominated transactions.

The following tables present information designed to provide insight into the overall volume of our derivatives usage. However, the volumes presented in these tables should only be used as an indication of the extent of our derivatives usage and the risks they are intended to manage and are subject to a number of limitations as follows:

- The volume information is not a complete representation of our market price risk because it only includes derivative contracts. Accordingly, these tables do not present a complete picture of our overall net economic exposure, and should not be interpreted as an indication of open or unhedged commodity positions, because the use of derivatives is only one of the means by which we engage in and manage the risks of our business.
- The tables also do not include volumes of commodities under nonderivative contracts that we use to serve customers or manage our risks. Our actual net economic exposure from our generating facilities and NewEnergy activities is reduced by derivatives, and the exposure from our trading activities is managed and controlled through the risk measures discussed above. Therefore, the information in the tables below is only an indication of that portion of our business that we

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manage through derivatives and serves primarily to identify the extent of our derivatives activities and the types of risks that they are intended to manage.

- We have computed the derivative volumes for commodities by aggregating the absolute value of net positions within commodities for each year. This provides an indication of the level of derivatives activity, but it does not indicate either the direction of our position (long or short), or the overall size of our position. We believe this presentation gives an appropriate indication of the level of derivatives activity without unnecessarily revealing the size and direction of our derivatives positions. The disclosure of such could limit the effectiveness and profitability of our business activities.
- The volume information for commodity derivatives represents the "delta equivalent" quantity of those contracts rather than the gross notional amount. We believe that the delta equivalent quantity is the most relevant measure of the volume associated with these commodity derivatives. The delta-equivalent quantity represents a risk-adjusted notional quantity for each contract that takes into account the probability that an option will be exercised. For interest rate contracts and foreign currency contracts we have presented the notional amounts of such contracts in the tables below.

The following tables present the volume of our derivative activities as of June 30, 2011 and December 31, 2010 shown by contractual settlement year.

Quantities[1] Under Derivative Contracts						***As of June 30, 2011***	
Contract Type (Unit)	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Power (MWH)	17.3	12.4	11.8	2.6	2.4	1.4	47.9
Gas (mmBTU)	123.4	134.2	47.3	64.4	29.8	0.9	400.0
Coal (Tons)	2.1	2.1	0.9				5.1
Oil (BBL)	0.2	0.2	0.1				0.5
Emission Allowances (Tons)	0.9	0.1					1.0
Renewable Energy Credits (Number of credits)	0.3	0.3	0.3	0.3	0.3	0.4	1.9
Interest Rate Contracts	$ 97.8	$ 884.3	$ 568.2	$ 185.0	$ 1,150.0	$ 315.0	$ 3,200.3
Foreign Exchange Rate Contracts	$ 16.8	$ 17.5	$ 16.7	$ 16.8	$ 15.5	$	$ 83.3

Quantities[1] Under Derivative Contracts						***As of December 31, 2010***	
Contract Type (Unit)	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
				(In millions)			
Power (MWH)	21.2		3.8	4.2	2.3	0.2	31.7
Gas (mmBTU)	175.3	90.1	80.2	64.7	24.1		434.4
Coal (Tons)	4.4	2.5	0.1				7.0
Oil (BBL)	0.2	0.1	0.1				0.4
Emission Allowances (Tons)	1.5						1.5
Renewable Energy Credits (Number of credits)	0.4	0.3	0.3	0.3	0.3	0.7	2.3
Interest Rate Contracts	$ 639.4	$ 490.7	$ 941.8	$ 405.0	$ 460.0	$ 175.0	$ 3,111.9
Foreign Exchange Rate Contracts	$ 48.7	$ 8.7	$ 16.8	$ 16.8	$ 15.5	$	$ 106.5

1 Amounts in the tables are only intended to provide an indication of the level of derivatives activity and should not be interpreted as a measure of any derivative position or overall economic exposure to market risk. Quantities are expressed as "delta equivalents" on an absolute value basis by contract type by year. Additionally, quantities relate only to derivatives and do not include potentially offsetting quantities associated with physical assets and nonderivative accrual contracts.

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Credit-Risk Related Contingent Features

Certain of our derivative instruments contain provisions that would require additional collateral upon a credit-related event such as an adequate assurance provision or a credit rating decrease in the senior unsecured debt of Constellation Energy. The amount of collateral we could be required to post would be determined by the fair value of contracts containing such provisions that represent a net liability, after offset for the fair value of any asset contracts with the same counterparty under master netting agreements and any other collateral already posted. This collateral amount is a component of, and is not in addition to, the total collateral we could be required to post for all contracts upon a credit rating decrease.

The following tables present information related to credit-risk related contingent features of our derivatives at June 30, 2011 and December 31, 2010.

Credit-Risk Related Contingent Feature — ***As of June 30, 2011***

Gross Fair Value of Derivative Contracts Containing This Feature[1]	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements[2]	Net Fair Value of Derivative Contracts Containing This Feature[3]	Amount of Posted Collateral[4]	Contingent Collateral Obligation[5]
		(In billions)		
$ 3.1	$ (2.6)	$ 0.5	$ 0.4	$ 0.1

Credit-Risk Related Contingent Feature — ***As of December 31, 2010***

Gross Fair Value of Derivative Contracts Containing This Feature[1]	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Agreements[2]	Net Fair Value of Derivative Contracts Containing This Feature[3]	Amount of Posted Collateral[4]	Contingent Collateral Obligation[5]
		(In billions)		
$ 4.6	$ (3.7)	$ 0.9	$ 0.7	$ 0.1

1 Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.

2 Amount represents the offsetting fair value of in-the-money derivative contracts under legally-enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we potentially could be required to post collateral.

3 Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

4 Amount includes cash collateral posted of $2.5 million and letters of credit of $412.4 million at June 30, 2011 and cash collateral posted of $0.6 million and letters of credit of $656.9 million at December 31, 2010.

5 Amounts represent the additional collateral that we could be required to post with counterparties, including both cash collateral and letters of credit, in the event of a credit downgrade to below investment grade after giving consideration to offsetting derivative and non-derivative *positions under master netting agreements.*

Concentrations of Credit Risk

We discuss our concentrations of credit risk, including derivative-related positions, in *Note 1* to our 2010 Annual Report on Form 10-K. As of June 30, 2011, we had a total exposure of 14% to one counterparty, a large power cooperative.

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Fair Value Measurements

Recurring Measurements

Our assets and liabilities measured at fair value on a recurring basis consist of the following (immaterial for BGE assets):

	As of June 30, 2011		As of December 31, 2010	
	Assets	Liabilities	Assets	Liabilities
	(In millions)			
Cash equivalents	$ 316.6	$	$ 1,545.4	$
Equity securities	44.2		43.7	
Derivative instruments:				
Classified as derivative assets and liabilities:				
Current	324.3	(494.2)	534.4	(622.3)
Noncurrent	257.5	(270.1)	258.9	(353.0)
Total classified as derivative assets and liabilities	581.8	(764.3)	793.3	(975.3)
Classified as accounts receivable[1]	(72.7)		(16.4)	
Total derivative instruments	509.1	(764.3)	776.9	(975.3)
Total recurring fair value measurements	$ 869.9	$ (764.3)	$ 2,366.0	$ (975.3)

1 Represents the unrealized fair value of exchange traded derivatives, exclusive of cash margin posted.

Cash equivalents represent money market funds included in "Cash and cash equivalents" in the Consolidated Balance Sheets. Equity securities primarily represent mutual fund investments included in "Other assets" in the Consolidated Balance Sheets. Derivative instruments represent unrealized amounts related to all derivatives. We classify exchange-listed derivatives as part of "Accounts Receivable" in our Consolidated Balance Sheets. We classify the remainder of our derivatives as "Derivative assets" or "Derivative liabilities" in our Consolidated Balance Sheets.

The table below sets forth by level within the fair value hierarchy the gross components of the Company's assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2011 and December 31, 2010. We disaggregate our net derivative assets and liabilities by separating each individual derivative contract that is in-the-money from each contract that is out-of-the-money regardless of master netting agreements and collateral. As a result, the gross "asset" and "liability" amounts in each of the three fair value levels far exceed our actual economic exposure to commodity price risk and credit risk. The objective of this table is to provide information about how each individual derivative contract is valued within the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts or whether it has been collateralized. Therefore, these gross balances are intended solely to provide information on sources of inputs to fair value and proportions of fair value involving objective versus subjective valuations and do not represent either our actual credit exposure or net economic exposure.

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At June 30, 2011	Level 1	Level 2	Level 3	Netting and Cash Collateral[1]	Total Net Fair Value
			(In millions)		
Cash equivalents	$ 316.6	$	$	$	$ 316.6
Equity securities	44.2				44.2
Derivative assets:					
Power contracts		4,718.2	873.5		
Gas contracts	68.9	3,568.9	451.0		
Coal contracts		209.1	0.6		
Other commodity contracts	50.7	58.6	196.6		
Interest rate contracts	35.8	40.2			
Foreign exchange contracts		13.7			
Total derivative assets	155.4	8,608.7	1,521.7	(9,776.7)	509.1
Derivative liabilities:					
Power contracts		(5,004.4)	(1,011.0)		
Gas contracts	(66.5)	(3,530.6)	(351.5)		
Coal contracts		(174.8)			
Other commodity contracts	(48.7)	(51.8)	(199.3)		
Interest rate contracts	(37.9)				
Foreign exchange contracts		(8.2)			
Total derivative liabilities	(153.1)	(8,769.8)	(1,561.8)	9,720.4	(764.3)
Net derivative position	2.3	(161.1)	(40.1)	(56.3)	(255.2)
Total	$ 363.1	$ (161.1)	$ (40.1)	$ (56.3)	$ 105.6

1 We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master netting agreement exists between us and the counterparty to a derivative contract. At June 30, 2011, we included $58.8 million of cash collateral held and $2.5 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.

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At December 31, 2010	Level 1	Level 2	Level 3	Netting and Cash Collateral[1]	Total Net Fair Value
			(In millions)		
Cash equivalents	$ 1,545.4	$	$	$	$ 1,545.4
Equity securities	43.7				43.7
Derivative assets:					
Power contracts		7,509.6	453.3		
Gas contracts	63.9	5,113.3	115.2		
Coal contracts		355.6	7.4		
Other commodity contracts	6.6	54.8			
Interest rate contracts	33.1	37.0			
Foreign exchange contracts		11.0			
Total derivative assets	103.6	13,081.3	575.9	(12,983.9)	776.9
Derivative liabilities:					
Power contracts		(7,758.2)	(771.1)		
Gas contracts	(72.7)	(4,910.3)	(5.1)		
Coal contracts		(307.4)	(0.9)		
Other commodity contracts	(7.1)	(54.5)			
Interest rate contracts	(35.7)				
Foreign exchange contracts		(8.4)			
Total derivative liabilities	(115.5)	(13,038.8)	(777.1)	12,956.1	(975.3)
Net derivative position	(11.9)	42.5	(201.2)	(27.8)	(198.4)
Total	$ 1,577.2	$ 42.5	$ (201.2)	$ (27.8)	$ 1,390.7

1 We present our derivative assets and liabilities in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities, including cash collateral, when a legally enforceable master netting agreement exists between us and the counterparty to a derivative contract. At December 31, 2010, we included $28.4 million of cash collateral held and $0.6 million of cash collateral posted (excluding margin posted on exchange traded derivatives) in netting amounts in the above table.

We discuss our valuation techniques and inputs used to develop those measurements in greater detail in *Note 13* of our 2010 Annual Report of Form 10-K. There have not been significant changes to our valuation techniques nor to their inputs during 2011.

During the quarter and six months ended June 30, 2011, there were no significant transfers of derivatives between Level 1 and Level 2 of the fair value hierarchy.

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During the quarters and six months ended June 30, 2011 and 2010, our Level 3 fair value measurements, predominantly power contracts, changed as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Balance at beginning of period	**$ (172.8)**	$ (315.2)	**$ (201.2)**	$ (291.5)
Realized and unrealized (losses) gains:				
Recorded in income	**39.8**	58.0	**(20.5)**	(78.7)
Recorded in other comprehensive income	**19.2**	(2.8)	**29.5**	73.6
Purchases	**(3.6)**		**(3.6)**	
Sales				
Issuances	**(3.5)**		**1.1**	
Settlements				
Net purchases, sales, issuances, and settlements[1]	**(7.1)**	7.4	**(2.5)**	16.6
Transfers into Level 3[2]	**34.1**	93.0	**145.7**	208.0
Transfers out of Level 3[2]	**46.7**	(16.1)	**8.9**	(103.7)
Balance at end of period	**$ (40.1)**	$ (175.7)	**$ (40.1)**	$ (175.7)
Change in unrealized gains recorded in income relating to derivatives still held at end of period	**$ 23.0**	$ 82.9	**$ (1.4)**	$ 8.9

1 Effective January 1, 2011, we are required to present separately purchases, sales, issuances, and settlements.

2 For purposes of this reconciliation, we assumed transfers into and out of Level 3 occurred on the last day of the quarter. All transfers are predominantly the result of changes in the observability of the forward commodity price curves.

We have defined the categories of purchases, sales, issuances, and settlements to include the inflow or outflow of value as follows:

- purchases includes the acquisition of pre-existing derivative contracts,
- sales includes the sale or assignment of pre-existing derivative contracts,
- issuances includes the acquisition of derivative contracts at inception, and
- settlements includes the termination of existing derivative contracts prior to normal maturity or settlement.

During the quarter and six months ended June 30, 2011, we had purchases related to our acquisition of StarTex and our issuances related to premiums paid for option contracts.

We discuss the financial statement classification for realized and unrealized gains and losses related to cash-flow hedges for our various hedging relationships in *Note 1* to our 2010 Annual Report on Form 10-K.

Fair Value of Financial Instruments

We show the carrying amounts and fair values of financial instruments included in our Consolidated Balance Sheets in the following table:

At June 30, 2011	Carrying Amount	Fair Value

		(In millions)	
Investments and other assets	Constellation Energy	$ 179.5	$ 179.8
Fixed-rate long-term debt:			
Constellation Energy (including BGE)		3,843.0	4,187.5
BGE		2,113.9	2,284.1
Variable-rate long-term debt:			
Constellation Energy (including BGE)		671.8	671.8
BGE			

We discuss our valuation techniques and assumptions for estimating the fair value of financial instruments in *Note 13* of our 2010 Annual Report on Form 10-K. There have been no changes in these techniques and assumptions during the quarter and six months ended June 30, 2011.

Accounting Standards Issued

Fair Value Measurements

In May 2011, the Financial Accounting Standards Board (FASB) issued updated guidance on fair value measurements and disclosure requirements. The update aligns the accounting requirements for fair value measurements under generally accepted accounting principles in the United States and international financial reporting standards. The new requirements will be effective for us as of January 1, 2012. We do not expect the adoption of this update to have a material impact on our, or BGE's financial results; however, it will result in additional disclosures.

Comprehensive Income

In June 2011, the FASB issued updated requirements on the presentation of comprehensive income which eliminate the option to present other comprehensive income in the statement of changes in equity. The new requirements will be effective for us as of January 1, 2012. We do not expect the adoption of this amendment to have an impact on our, or BGE's financial results, other than the presentation of a separate statement of comprehensive income.

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Related Party Transactions

Constellation Energy

CENG

We have a unit contingent power purchase agreement (PPA) with CENG under which we will purchase between 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, we will purchase 50.01% of the output of CENG's nuclear plants, and EDF will purchase 49.99% of that output.

In addition to the PPA, we have a power services agency agreement (PSA) and an administrative service agreement (ASA) with CENG. The PSA is a five-year agreement under which we will provide scheduling, asset management and billing services to CENG and recognize average annual revenue of approximately $16 million. The ASA expires in 2017 and under the agreement we provide certain administrative services to CENG including back office, human resources and information technology. The ASA includes both a consumption-based pricing structure as well as a fixed-price structure which are subject to change in future years based on the level of service needed. The fixed price fee for 2011 is approximately $48 million and will increase annually in line with inflation. The charges under this agreement are intended to represent the actual cost of the services provided to CENG by us.

The impact of transactions under these agreements is summarized below:

	Increase (Decrease) in Earnings					At June 30, 2011	At December 31, 2010
	Quarter Ended June 30,		Six Months Ended June 30,		Income Statement	Accounts Receivable/ (Accounts	Accounts Receivable/ (Accounts
Agreement	2011	2010	2011	2010	Classification	Payable)	Payable)
PPA	$ (209.3)	$ (222.1)	$ (404.1)	$ (420.6)	Fuel and purchased energy expenses	$ (46.5)	$ (47.6)
PSA	4.0	4.0	8.0	8.0	Nonregulated revenues		
ASA	12.0	16.5	24.0	33.0	Operating expenses	4.0	5.5

In May 2011, CENG issued an unsecured revolving promissory note to borrow up to an aggregate principal amount of $62.5 million from a subsidiary of Constellation Energy. CENG also issued a promissory note to EDF on substantially identical terms, such that any request for borrowings by CENG must be submitted 50% to Constellation Energy and 50% to EDF.

Interest accrues on the amounts borrowed on a daily basis at a fixed rate per year equal to the rate at which deposits of United States dollars are offered by prime banks in the London interbank market, plus 250 basis points. Amounts are due at the earlier of October 31, 2012 or the date upon which the note is accelerated in accordance with the terms of the agreement.

As of June 30, 2011, CENG has borrowed $15.0 million from Constellation Energy.

In June 2011, CENG executed a settlement agreement with the DOE under which Constellation Energy will receive payment of $35.5 million related to costs incurred through October 31, 2008 to store spent nuclear fuel at the Calvert Cliffs nuclear power plant. As a result, we recorded $35.5 million as an amount due from CENG in "Accounts receivable" on our Consolidated Balance Sheets. We discuss this settlement in more detail on page 12.

BGE Income Statement

BGE is obligated to provide market-based standard offer service to all of its electric customers for varying periods. Bidding to supply BGE's market-based standard offer service to electric customers will occur from time to time through a competitive bidding process approved by the Maryland PSC.

Our NewEnergy business will supply a portion of BGE's market-based standard offer service obligation to electric customers through September 30, 2013.

The cost of BGE's purchased energy from nonregulated subsidiaries of Constellation Energy to meet its standard offer service obligation was as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Purchased energy	**$ 73.2**	$ 114.6	**$ 129.9**	$ 238.6

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs, both capital and expense, are directly assigned to BGE. We allocate other corporate function costs based on a total percentage of expected use by BGE. We believe this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity.

The following table presents all of the costs Constellation Energy charged to BGE in each period, both directly-charged and allocated.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Charges to BGE	**$ 44.3**	$ 42.3	**$ 91.8**	$ 78.5

Other nonregulated affiliates of BGE also charge BGE for the costs of certain services provided.

BGE Balance Sheet

BGE's Consolidated Balance Sheets include intercompany amounts related to BGE's purchases to meet its standard offer service obligation, BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them, Constellation Energy and its nonregulated affiliates' charges to BGE, and the participation of BGE's employees in the Constellation Energy defined benefit plans.

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Item 2.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries and joint ventures organized around three business segments: a generation business (Generation), a customer supply business (NewEnergy), and Baltimore Gas and Electric Company (BGE). We describe our business segments in detail in *Note 3* of our 2010 Annual Report on Form 10-K.

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE. We discuss our business and strategy in more detail in *Item 1 Business* section of our 2010 Annual Report on Form 10-K and we discuss the risks affecting our business in *Item 1A. Risk Factors* section beginning on page 60 and in our 2010 Annual Report on Form 10-K.

Our 2010 Annual Report on Form 10-K includes a detailed discussion of various items impacting our business, our results of operations, and our financial condition. These include:

- *Introduction and Overview* section which provides a description of our business,
- *Strategy* section,
- *Business Environment* section, including how recent events, regulation, weather, and other factors affect our business, and
- *Critical Accounting Policies* section.

Critical accounting policies are the accounting policies that are most important to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective, or complex judgment. Our critical accounting policies include derivative accounting and the evaluation of assets for impairment and other than temporary decline in value.

In this discussion and analysis, we explain the general financial condition and the results of operations for Constellation Energy and BGE including:

- factors which affect our businesses,
- our earnings and costs in the periods presented,
- changes in earnings and costs between periods,
- sources of earnings,
- impact of these factors on our overall financial condition,
- expected future expenditures for capital projects,
- expected sources of cash for future capital expenditures, and
- our net available liquidity and collateral requirements.

As you read this discussion and analysis, refer to our Consolidated Statements of Income on page 1, which present the results of our operations for the quarters and six months ended June 30, 2011 and 2010. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- We describe changes to our business environment during the year.
- We highlight significant events that occurred in 2011 that are important to understanding our results of operations and financial condition.
- We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition, addressing our sources and uses of cash, capital resources, commitments, and liquidity.
- We conclude with a discussion of our exposure to various market risks.

Business Environment

Various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 64 and in *Item 1A. Risk Factors* section beginning on page 60 and in our 2010 Annual Report on Form 10-K. We discuss our market risks in the *Risk Management* section beginning on page 56.

The volatility of the financial, credit and global energy markets impacts our liquidity and collateral requirements as well as our credit risk. We discuss our liquidity and collateral requirements in the *Financial Condition* section and our customer (counterparty) credit and other risks in more detail in the *Risk Management* section.

In this section, we discuss in more detail events which have impacted our business during 2011.

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Regulation Maryland

Base Rates

In March 2011, the Maryland PSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. We discuss certain details of the comprehensive order in the *Notes to Consolidated Financial Statements* on page 13.

Potential Reliability and Quality of Service Standards

During its 2011 legislative session, the Maryland General Assembly passed legislation:

- directing the Maryland PSC to enact service quality and reliability regulations by July 1, 2012 relating to the delivery of electricity to retail electric customers,
- increasing existing penalties for failure to meet these and other Maryland PSC regulations, and
- directing the Maryland PSC to undertake certain studies addressing utility liability for certain customer damages, electric utility service restoration plans, and modifications to existing revenue decoupling mechanisms for extended service interruptions. f

In May 2011, the Governor signed this legislation into law and the Maryland PSC has instituted a rulemaking proceeding to begin drafting the required service quality and reliability regulations. We cannot at this time predict the final outcome of this rulemaking or the studies required under the legislation or how such outcome may affect our, or BGE's, financial results.

Environmental Matters

Air Quality

Federal

In July 2011, the Environmental Protection Agency (EPA) adopted the Cross-State Air Pollution Rule (CSAPR). Initially proposed in July 2010, the rule replaces the Clean Air Interstate Rule (CAIR) and will limit sulfur dioxide and nitrogen oxide emissions in 27 states beginning January 1, 2012 through the implementation of federal and state plans. We are still evaluating the requirements of this new rule, but generally anticipate that we will not have a material change to our emissions reduction plan in Maryland as the emissions reduction requirements of Maryland's Healthy Air Act are similar in magnitude and are in effect currently. However, CSAPR is more stringent than the 2010 proposed EPA rule, with marginally tighter emission caps, which, depending on the scope of the implementation plans, could result in additional compliance costs.

Events of 2011

Pending Merger with Exelon Corporation

On April 28, 2011, we entered into an Agreement and Plan of Merger with Exelon Corporation (Exelon). At closing, each issued and outstanding share of common stock of Constellation Energy will be cancelled and converted into the right to receive 0.93 shares of common stock of Exelon, and Constellation Energy will become a wholly owned subsidiary of Exelon.

Prior to the completion of the merger, which is subject to shareholder and various regulatory approvals, Constellation Energy will continue to operate as a separate company. The discussion and analysis of our results of operations and financial condition beginning on the next page relates solely to Constellation Energy.

We discuss this transaction and the costs incurred to date in more detail on page 9 in *Notes to Consolidated Financial Statements*.

Acquisitions

MXenergy Holdings Inc.

In July 2011, we acquired all of the outstanding stock of MXenergy Holdings Inc. (MXenergy), a retail energy marketer of natural gas and electric power to residential and commercial customers in deregulated markets in the United States and Canada for approximately $175 million, subject to certain purchase price adjustments. We discuss this transaction in more detail on page 11 in *Notes to Consolidated Financial Statements*.

Star Electricity, Inc.

In May 2011, we acquired all of the outstanding stock of Star Electricity, Inc. (StarTex), a retail electric provider, for $163.5 million in cash, all of which was paid at closing. We discuss this transaction in more detail on page 11 in *Notes to Consolidated Financial Statements.*

Boston Generating

In January 2011, we completed the acquisition of Boston Generating's 2,950 MW fleet of generating plants for approximately $1.1 billion. We discuss this transaction in more detail beginning on page 11 in *Notes to Consolidated Financial Statements.*

Divestitures

Constellation Energy Partners LLC

In June 2011, we entered into a definitive purchase and sale agreement with PostRock Energy Corporation (PostRock) for the sale of all of our interests in Constellation Energy Partners LLC (CEP) for cash, shares of PostRock common stock and warrants to buy additional shares of PostRock common stock. The transaction is subject to the approval by the independent directors of CEP and the shareholders of PostRock. We expect the transaction to close in 2011. We discuss this transaction in more detail on page 12.

Quail Run Energy Center

In June 2011, we terminated the agreement to sell our Quail Run Energy Center (Quail Run), a 550 MW natural gas plant in west Texas, to High Plains Diversified Energy Corporation. We had previously entered into the agreement to sell Quail Run in December 2010. We discuss this development on page 12.

Settlement with U.S. Department of Energy (DOE)

In June 2011, we recognized a $35.5 million pre-tax gain related to an agreement with the DOE that settled a lawsuit that sought to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel at the Calvert Cliffs nuclear plant. We discuss this settlement in more detail on page 12 in *Notes to Consolidated Financial Statements*.

Financings

Secured Solar Credit Facility

In July 2011, a subsidiary of Constellation Energy entered into a three year senior secured credit facility associated with certain solar projects that we own. The amount committed under the facility is $150 million, which may be increased up to a total amount of $200 million at the subsidiary's request with additional commitments by the lenders. Obligations under this facility are secured by the equity interests in the subsidiary and the entities that own the solar projects as well as the assets of the subsidiary of each project entity and are guaranteed by Constellation Energy and the project entities.

Amended Reserve-Based Facility for Upstream Gas Operations

In July 2011, we amended and extended our existing reserve based lending facility that supports our upstream gas operations. The borrowing base committed under the facility was increased to $150 million and can grow up to $500 million if the assets support a higher borrowing base and if we are able to obtain additional commitments from lenders. The facility expires in July 2016 and any borrowings under this facility are secured by the upstream gas properties.

Sacramento Solar Project Facility

In July 2011, a subsidiary of Constellation Energy entered into a $40 million nonrecourse project financing to fund construction of our 30MW solar facility in Sacramento, California. Borrowings will incur interest at a variable rate, payable quarterly, and are secured by the equity interests and assets of the subsidiary. The construction borrowings will convert into a 19-year variable rate note upon commercial operation of the facility.

We discuss these financings in more detail on page 16 in *Notes to Consolidated Financial Statements*.

Revolving Promissory Note with CENG

In May 2011, CENG issued an unsecured revolving promissory note to borrow up to an aggregate principal amount of $62.5 million from a subsidiary of Constellation Energy. We discuss this related party financing on page 36 in *Notes to Consolidated Financial Statements*.

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Results of Operations for the Quarter and Six Months Ended June 30, 2011 Compared with the Same Periods of 2010

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments. Significant changes in other (expense) income, fixed charges, and income taxes are discussed, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 51.

Overview

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions, after-tax)			
Generation	**$ 40.9**	$ 15.3	**$ 53.7**	$ 42.4
NewEnergy	**51.7**	50.8	**40.3**	154.9
Regulated electric	**22.9**	20.9	**62.6**	48.1
Regulated gas	**(6.3)**	(3.9)	**35.1**	33.3
Other nonregulated	**(1.1)**	0.7	**(4.2)**	(3.6)
Net Income	**$ 108.1**	$ 83.8	**$ 187.5**	$ 275.1
Net Income attributable to common stock	**$ 99.2**	$ 72.6	**$ 169.6**	$ 264.1
Change from prior year	**$ 26.6**		**$ (94.5)**	

Our total net income attributable to common stock increased $26.6 million, or $0.13 per share, during the quarter ended June 30, 2011 and decreased $94.5 million, or $0.47 per share, during the six months ended June 30, 2011, compared to the same periods of 2010, primarily due to the following:

	Quarter Ended June 30,	Six Months Ended June 30,
	2011 vs. 2010	
	(In millions, after-tax)	
Generation gross margin	$ 28	$ 16
Increases in Generation non-gross margin expenses related to:		
Acquisition of Boston Generating fleet of generating assets in January 2011	(22)	(43)
Acquisition of two combined cycle generating facilities in Texas in May 2010	(5)	(12)
NewEnergy gross margin	28	(110)
NewEnergy hedge ineffectiveness	(20)	1
Regulated businesses	5	19
Other nonregulated businesses	(2)	(5)
Total change in *Other Items included in operations* per table below	15	53
All other changes		(14)
Total Change	$ 27	$ (95)

Other Items Included in Operations (after-tax):

	Quarter Ended June 30, 2011	Quarter Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions, after-tax)			
Impact of power purchase agreement with CENG[1]	**$ (30.3)**	$ (29.1)	**$ (57.3)**	$ (54.8)
Amortization of basis difference in CENG	**(24.0)**	(37.0)	**(41.6)**	(62.7)
Gain on settlement with DOE	**21.3**		**21.3**	
Merger costs	**(19.3)**		**(19.3)**	
Transaction fees for Boston Generating acquisition	**(0.1)**		**(10.1)**	
Loss on early retirement of 2012 Notes				(30.9)
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits				(8.8)
Credit facility amendment fees	**(1.5)**	(2.9)	**(3.0)**	(5.8)
Total Other Items	**$ (53.9)**	$ (69.0)	**$ (110.0)**	$ (163.0)
Change from prior year	**$ 15.1**		**$ 53.0**	

1 The net impact to the Company of the power purchase agreement with CENG was $50.3 million and $95.2 million pre-tax for the quarter and six months ended June 30, 2011 and $47.7 million and $89.9 million for the quarter and six months ended June 30, 2010. This amount represents the amortization of our "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its "Unamortized energy contract liability."

In the following sections, we discuss our net income by business segment in greater detail.

Generation Business

Background

We define our Generation business in *Note 3* to our 2010 Annual Report on Form 10-K.

We have presented the results of this business reflecting that we have hedged 100% of generation output and fuel for generation. This is based on executing hedges at prevailing market prices with the NewEnergy business. Taking into account previously executed hedges at the end of each fiscal year, we ensure that the Generation business is fully hedged by the NewEnergy business for the next year. Therefore, all commodity price risk is managed by and presented in the results of our NewEnergy business as discussed below. Generally, changes in the results of our Generation business during the period are due to changes in the availability of the generating assets.

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Results

	Quarter Ended June 30, 2011	Quarter Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Revenues	**$ 676.5**	$ 550.3	**$ 1,344.1**	$ 1,130.2
Fuel and purchased energy expenses	**(395.0)**	(343.8)	**(809.4)**	(670.4)
Gross margin	**281.5**	206.5	**534.7**	459.8
Operating expenses	**(109.5)**	(90.0)	**(226.7)**	(184.6)
Merger costs	**(15.6)**		**(15.6)**	
Depreciation, depletion, accretion, and amortization	**(51.3)**	(32.0)	**(100.0)**	(60.5)
Taxes other than income taxes	**(11.9)**	(5.6)	**(23.8)**	(11.0)
Gain on divestitures				2.9
Equity investment (losses) earnings:				
CENG	**(25.0)**	(21.3)	**(41.6)**	(40.6)
UNE		(6.8)		(12.9)
Other	**(1.3)**	(5.4)	**5.7**	(0.7)
Gain on settlement with DOE	**35.5**		**35.5**	
Income from Operations	**$ 102.4**	$ 45.4	**$ 168.2**	$ 152.4
Net Income	**$ 40.9**	$ 15.3	**$ 53.7**	$ 42.4
Net Income attributable to common stock	**$ 40.9**	$ 15.3	**$ 53.7**	$ 42.4
Other Items Included in Operations (after-tax):				
Impact of power purchase agreement with CENG[1]	**$ (30.3)**	$ (29.1)	**$ (57.3)**	$ (54.8)
Amortization of basis difference in CENG	**(24.0)**	(37.0)	**(41.6)**	(62.7)
Gain on settlement with DOE	**21.3**		**21.3**	
Merger costs	**(9.5)**		**(9.5)**	
Transaction fees for Boston Generating acquisition	**(0.1)**		**(10.1)**	
Loss on early retirement of 2012 Notes				(30.9)
Credit facility amendment fees		(1.9)		(3.8)
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits				(0.8)
Total Other Items	**$ (42.6)**	$ (68.0)	**$ (97.2)**	$ (153.0)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

1 The net impact to the Company of the power purchase agreement with CENG was $50.3 million and $95.2 million pre-tax for the quarter and six months ended June 30, 2011 and $47.7 million and $89.9 million pre-tax for the quarter and six months ended June 30, 2010. This amount represents the amortization of our "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its "Unamortized energy contract liability."

Revenues

Our Generation revenues increased $126.2 million and $213.9 million in the quarter and six months ended June 30, 2011 compared to the same periods of 2010, primarily due to the following:

	Quarter Ended June 30,	Six Months Ended June 30,

	2011 vs. 2010	
	(In millions)	
Increase in volume of output, primarily due to the acquisition of the Boston Generating fleet of generating assets in January 2011	$ 95	$ 293
Increase (decrease) in contracted power prices	34	(132)
(Decrease) increase in volume of output due to (increased) reduced impact of outages at our fossil plants	(3)	53
Total increase in Generation revenues	$ 126	$ 214

Fuel and Purchased Energy Expenses

Our Generation fuel and purchased energy expenses increased $51.2 million and $139.0 million in the quarter and six months ended June 30, 2011 compared to the same periods of 2010, primarily due to the following:

	Quarter Ended June 30,	**Six Months Ended June 30,**
	2011 vs. 2010	
	(In millions)	
Increase in volume of gas consumed due to the acquisition of the Boston Generating fleet of generating assets in January 2011	$ 34	$ 88
Increase in coal fuel costs primarily due to price	48	65
(Decrease) increase due to (increased) reduced impact of outages at our fossil plants	(16)	12
All other	(15)	(26)
Total increase in Generation fuel and purchased energy expenses	$ 51	$ 139

Operating Expenses

Our Generation business operating expenses increased $19.5 million and $42.1 million for the quarter and six months ended June 30, 2011, respectively, as compared to the same periods of 2010 primarily due to the costs associated with the acquisition of the Boston Generating fleet of generating assets in January 2011.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail on page 9 in *Notes to Consolidated Financial Statements*.

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Depreciation, Depletion, Accretion, and Amortization Expense

Our Generation business incurred higher depreciation, depletion, accretion, and amortization expenses of $19.3 million and $39.5 million during the quarter and six months ended June 30, 2011 compared to the same periods of 2010 primarily due to an increase of $10.3 million and $18.3 million, respectively, in depreciation on the Boston Generating facilities acquired in January 2011, $4.2 million and $8.6 million, respectively, related to the June 2010 commencement of operations of our Hillabee Energy Center, and $1.5 million and $4.5 million, respectively, related to the May 2010 acquisition of the two Texas combined cycle generation facilities.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $6.3 million and $12.8 million during the quarter and six months ended June 30, 2011, respectively, compared to the same periods of 2010 primarily due to an increase in property taxes related to generating facilities acquired in Texas in 2010 and Massachusetts in 2011.

Equity Investment (Losses)

Our equity investment losses decreased $7.2 million and $18.3 million during the quarter and six months ended June 30, 2011, respectively, compared to the same periods of 2010 primarily due to the absence of $6.8 million and $12.9 million, respectively, of losses on our investment in UNE, which we sold in the fourth quarter of 2010. Additionally, the $3.7 million increase in equity losses related to our investment in CENG for the quarter ended June 30, 2011 compared to the same period of 2010 is primarily due to lower CENG operating results, partially offset by a decrease in the amortization of our basis difference in CENG. CENG's operating results reflected an increased number of outage days this quarter compared to the second quarter of 2010. We discuss our investment in CENG in more detail on page 13 in *Notes to Consolidated Financial Statements*.

Gain on Settlement with DOE

In June 2011, we recognized a $35.5 million pre-tax gain related to an agreement with the DOE that settled a lawsuit that sought to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel at the Calvert Cliffs nuclear power plant. We discuss this settlement in more detail on page 12 in *Notes to Consolidated Financial Statements*.

NewEnergy Business

Background

We define our NewEnergy business in *Note 3* to our 2010 Annual Report on Form 10-K.

Our NewEnergy business focuses on delivery of physical, customer-oriented energy products and services to energy producers and consumers, manages the risk and optimizes the value of our owned and contracted generation assets and NewEnergy activities, and uses our portfolio management and trading capabilities both to manage risk and to deploy limited risk capital. Our NewEnergy business actively transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions.

We discuss our revenue recognition policies in the *Critical Accounting Policies* section and *Note 1* of our 2010 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Revenues	**$ 2,559.8**	$ 2,390.8	**$ 4,971.9**	$ 4,741.7

Fuel and purchased energy expenses		**(2,196.3)**		(2,085.3)		**(4,396.0)**		(4,064.7)
Gross margin		**363.5**		305.5		**575.9**		677.0
Operating expenses		**(211.2)**		(190.6)		**(391.0)**		(359.1)
Merger costs		**(7.0)**				**(7.0)**		
Depreciation, depletion, accretion, and amortization		**(23.0)**		(20.9)		**(41.4)**		(42.7)
Taxes other than income taxes		**(17.5)**		(13.7)		**(32.8)**		(26.6)
Gain on divestitures				0.2				2.2
Income from Operations	**$**	**104.8**	$	80.5	**$**	**103.7**	$	250.8
Net Income	**$**	**51.7**	$	50.8	**$**	**40.3**	$	154.9
Net Income attributable to common stock	**$**	**46.1**	$	42.9	**$**	**29.0**	$	150.5
Other Items Included in Operations (after-tax):								
Merger costs	**$**	**(4.3)**	$		**$**	**(4.3)**	$	
Credit facility amendment fees		**(1.5)**		(1.0)		**(3.0)**		(2.0)
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits								(0.1)
Total Other Items	**$**	**(5.8)**	$	(1.0)	**$**	**(7.3)**	$	(2.1)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

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Revenues

Our NewEnergy revenues increased $169.0 million and $230.2 million in the quarter and six months ended June 30, 2011 compared to the same periods of 2010, primarily due to the following:

	Quarter Ended June 30,	Six Months Ended June 30,
	2011 vs. 2010	
	(In millions)	
Increase in wholesale load sales primarily driven by volume served	$ 162	$ 236
Change due to hedge ineffectiveness	28	11
(Decrease) increase in wholesale and retail mark-to-market revenues due primarily to changes in gas and power prices	(4)	29
Decrease in volume and contract prices related to our domestic coal operation	(3)	(21)
Decrease primarily due to absence of revenue from international contracts that were assigned in 2010	(37)	(41)
All other	23	16
Total increase in NewEnergy revenues	$ 169	$ 230

Fuel and Purchased Energy Expenses

Our NewEnergy fuel and purchased energy expenses increased $111.0 million and $331.3 million in the quarter and six months ended June 30, 2011 compared to the same periods of 2010, primarily due to the following:

	Quarter Ended June 30,	Six Months Ended June 30,
	2011 vs. 2010	
	(In millions)	
Increase in wholesale power purchases primarily driven by volume served	$ 118	$ 232
Change due to hedge ineffectiveness	(3)	10
Realization of fuel and purchased energy related to the assignment of international contracts	(20)	50
All other	16	39
Total increase in NewEnergy fuel and purchased energy expenses	$ 111	$ 331

The decrease in wholesale power gross margin for the six months ended June 30, 2011 compared to the same periods of 2010 reflects a less favorable price environment, primarily driven by the sudden, extreme drops in temperature, coupled with high winds, experienced in the Texas region during the first quarter of 2011. This weather event caused generation to go off-line and forced generators and load serving entities, like us, to purchase replacement power at significantly increased spot prices.

Mark-to-Market

Mark-to-market results include net gains and losses from origination, risk management, certain physical energy delivery activities, and trading activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section of our 2010 Annual Report on Form 10-K.

The nature of our operations and the use of mark-to-market accounting for certain activities create fluctuations in mark-to-market earnings. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Risk Management* section beginning on page 56. The primary factors that cause fluctuations in our mark-to-market results are:

- changes in the level and volatility of forward commodity prices and interest rates,
- counterparty creditworthiness,

- the number and size of our open derivative positions, and
- the number, size, and profitability of new transactions, including termination or restructuring of existing contracts.

Risk management and trading mark-to-market represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the effects of changes in valuation adjustments. In addition to our fundamental risk management and trading activities, we also use non-trading derivative contracts subject to mark-to-market accounting to manage our exposure to changes in market prices, while in general the underlying physical transactions related to these activities are accounted for on an accrual basis.

We discuss the changes in mark-to-market results below. We show the relationship between our mark-to-market results and the change in our net mark-to-market energy asset later in this section.

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Mark-to-market results were as follows:

	Quarter Ended June 30,				Six Months Ended June 30,			
	2011		**2010**		**2011**		**2010**	
	(In millions)							
Unrealized mark-to-market results								
Origination gains	**$**		$		**$**		$	
Risk management and trading mark-to-market								
Unrealized changes in fair value		**45.0**		47.1		**41.6**		10.9
Changes in valuation techniques								
Reclassification of settled contracts to realized		**(54.2)**		(26.7)		**(131.2)**		(216.8)
Total risk management and trading mark-to-market		**(9.2)**		20.4		**(89.6)**		(205.9)
Total unrealized mark-to-market[1]		**(9.2)**		20.4		**(89.6)**		(205.9)
Realized mark-to-market		**54.2**		26.7		**131.2**		216.8
Total mark-to-market results[2]	**$**	**45.0**	$	47.1	**$**	**41.6**	$	10.9

1 Total unrealized mark-to-market is the sum of origination gains and total risk management and trading mark-to-market.

2 Includes gains (losses) on hedge ineffectiveness for fair value hedges recorded in gross margin.

Total mark-to-market results decreased $2.1 million during the quarter ended June 30, 2011 compared to the same period of 2010 due to $36.3 million of lower results in our Alberta and NEPOOL power and transmission risk management activities driven by a less favorable price environment.

These decreases were partially offset by the following:

- $25.8 million of higher results on unrealized positions due to a more favorable price environment related to economic hedges of our upstream gas operation, and
- $8.4 million of higher results in our domestic coal portfolio due to a more favorable price environment.

Total mark-to-market results increased $30.7 million during the six months ended June 30, 2011 compared to the same period of 2010 due to unrealized changes in fair value primarily due to a more favorable price environment as follows:

- $22.7 million related to unrealized positions in our retail power and gas operations, and
- $11.6 million related to other activity primarily due to unrealized positions in our power and transmission risk management activities within the Texas region as well as the absence of losses in the PJM, West, and New York regions due to a more favorable price environment.

These increases were partially offset by $3.6 million of lower results on unrealized positions due to a less favorable price environment related to economic hedges of our upstream gas operation.

Derivative Assets and Liabilities

Derivative assets and liabilities, excluding exchange-traded derivatives classified as accounts receivable consisted of the following:

	June 30, 2011	December 31, 2010
	(In millions)	
Current Assets	**$ 324.3**	$ 534.4
Noncurrent Assets	**257.5**	258.9
Total Assets	**581.8**	793.3
Current Liabilities	**494.2**	622.3
Noncurrent Liabilities	**270.1**	353.0
Total Liabilities	**764.3**	975.3
Net Derivative Position	**$ (182.5)**	$ (182.0)
Composition of net derivative exposure:		
Hedges	**$ (314.7)**	$ (504.5)
Mark-to-market	**188.5**	350.3
Net cash collateral included in derivative balances	**(56.3)**	(27.8)
Net Derivative Position	**$ (182.5)**	$ (182.0)

Derivative balances above include noncurrent assets related to our Generation business of $35.3 million and $35.7 million at June 30, 2011 and December 31, 2010, respectively. Derivative balances related to our Generation business consist of interest rate contracts accounted for as fair value hedges. We discuss our derivative assets and liabilities in further detail in the Notes to Consolidated Financial Statements.

The decrease of $189.8 million in our net derivative liability subject to hedge accounting since December 31, 2010 was due to $250.6 million of realization of out-of-the-money cash-flow hedges at the time the forecasted transaction occurred, partially offset by $60.8 million of increases on our net out-of-the-money cash-flow hedge positions primarily related to decreases in natural gas prices during 2011.

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The following are the primary sources of the change in our net derivative asset subject to mark-to-market accounting during the quarter and six months ended June 30, 2011:

	Quarter Ended June 30, 2011	Six Months Ended June 30, 2011
	(In millions)	
Fair value beginning of period	$ 232.4	$ 350.3
Changes in fair value recorded in earnings		
Origination gains	$	$
Unrealized changes in fair value	45.0	41.6
Changes in valuation techniques		
Reclassification of settled contracts to realized	(54.2)	(131.2)
Total changes in fair value	(9.2)	(89.6)
Changes in value of exchange-listed futures and options	(43.7)	(132.6)
Net change in premiums on options	(29.3)	(35.7)
Contracts acquired	(6.5)	(8.0)
Dedesignated contracts and other changes in fair value	44.8	104.1
Fair value at end of period	$ 188.5	$ 188.5

We describe the types of changes in our net derivative asset subject to mark-to-market accounting that affected earnings in *Item 7. Management's Discussion and Analysis* in our 2010 Annual Report on Form 10-K.

The settlement terms of the portion of our net derivative asset subject to mark-to-market accounting and sources of fair value based on the fair value hierarchy are as follows as of June 30, 2011:

	Settlement Term							
	2011	2012	2013	2014	2015	2016	Thereafter	Fair Value
	(In millions)							
Level 1	$ 0.4	$	$	$	$	$	$	$ 0.4
Level 2	142.2	244.3	6.7	0.5	5.8	0.6	0.2	400.3
Level 3	59.8	(251.4)	(19.9)	5.6	2.8	4.2	(13.3)	(212.2)
Total net derivative asset (liability) subject to mark-to-market accounting	$ 202.4	$ (7.1)	$ (13.2)	$ 6.1	$ 8.6	$ 4.8	$ (13.1)	$ 188.5

Operating Expenses

Our NewEnergy business operating expenses increased $20.6 million and $31.9 million during the quarter and six months ended June 30, 2011 as compared to the same periods of 2010 primarily due to growth in this business segment: $9.8 million and $12.9 million, respectively, due to acquisitions, and $6.0 million and $7.4 million, respectively, due to an increase in marketing and advertising related to our residential electricity program.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail on page 9 in *Notes to Consolidated Financial Statements*.

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Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section of our 2010 Annual Report on Form 10-K.

Results

	Quarter Ended June 30, 2011	Quarter Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Revenues	**$ 547.1**	$ 651.1	**$ 1,197.3**	$ 1,402.4
Electricity purchased for resale expenses	**(272.7)**	(401.4)	**(626.6)**	(875.0)
Operations and maintenance expenses	**(116.6)**	(107.4)	**(229.5)**	(221.2)
Merger costs	**(6.9)**		**(6.9)**	
Depreciation and amortization	**(55.4)**	(49.6)	**(119.4)**	(106.0)
Taxes other than income taxes	**(38.2)**	(36.9)	**(77.2)**	(74.1)
Income from Operations	**$ 57.3**	$ 55.8	**$ 137.7**	$ 126.1
Net Income	**$ 22.9**	$ 20.9	**$ 62.6**	$ 48.1
Net Income attributable to common stock	**$ 20.5**	$ 18.4	**$ 57.7**	$ 43.0
Other Items Included in Operations (after-tax):				
Merger costs[1]	**$ (4.1)**	$	**$ (4.1)**	$
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits				(3.1)
Total Other Items	**$ (4.1)**	$	**$ (4.1)**	$ (3.1)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

1 BGE will not seek recovery of these costs in rates.

Net income attributable to common stock from the regulated electric business increased $14.7 million during the six months ended June 30, 2011 compared to the same period in 2010, primarily due to an increase in base rate distribution revenues of $10.7 million after-tax resulting from the December 2010 Maryland PSC order discussed below.

Electric Revenues

The changes in electric revenues during the quarter and six months ended June 30, 2011 compared to the same periods of 2010 were caused by:

	Quarter Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
	(In millions)	
Distribution volumes	$ (9.7)	$ (5.7)
Base rates	10.4	17.0
Smart Energy Savers Program[SM] surcharges	4.0	8.5

Revenue decoupling		5.3		0.4
Standard offer service		(124.0)		(244.2)
Rate stabilization recovery		(2.2)		(5.2)
Senate Bill 1 credits		0.8		(2.9)
Total change in electric revenues from electric system sales		(115.4)		(232.1)
Other		11.4		27.0
Total change in electric revenues	$	(104.0)	$	(205.1)

Distribution Volumes

Distribution volumes are the amount of electricity that BGE delivers to customers in its service territory.

The percentage changes in our electric distribution volumes, by type of customer, in 2011 compared to 2010 were:

	Quarter Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
Residential	(10.9)%	(7.0)%
Commercial	4.1	2.9
Industrial	(11.1)	(13.9)

During the quarter and six months ended June 30, 2011 compared to the same periods of 2010, we distributed less electricity to residential customers due to milder weather, partially offset by increased usage per customer and an increased number of customers. We distributed more electricity to commercial customers due to increased usage per customer and an increased number of customers. We distributed less electricity to industrial customers primarily due to a decreased number of customers.

Base Rates

On December 6, 2010, the Maryland PSC authorized BGE to increase electric distribution rates by $31.0 million for service rendered on or after December 4, 2010. This increase was based upon an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio. We discuss BGE's electric base rates in *Notes to Consolidated Financial Statements* on page 13.

Smart Energy Savers Program^{SM} Surcharges

Beginning in 2009, the Maryland PSC approved customer surcharges through which BGE recovers costs associated with certain programs designed to help BGE manage peak demand and encourage customer energy conservation.

Revenues increased for the quarter and six months ended June 30, 2011 compared to the same periods in 2010, primarily due to an increase in customer surcharge rates in 2011.

Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier.

Standard offer service revenues decreased during the quarter and six months ended June 30, 2011 compared to the same periods of 2010 mostly due to a decrease in the standard offer service rates of $46.1 million and $97.7 million, respectively, and the impact of lower standard offer service volumes of $77.9 million and $146.5 million, respectively. The volume decrease is primarily due to an increase in customers using competitive suppliers.

Rate Stabilization Recovery

In late June 2007, BGE began recovering amounts deferred during the first rate deferral period that ended on May 31, 2007. The recovery of these amounts is occurring over a ten year period.

Rate stabilization recovery revenue decreased during the quarter and six months ended June 30, 2011 compared to the same periods of 2010 primarily due to a decrease in recovery rates charged to customers.

Senate Bill 1 Credits

As a result of Senate Bill 1, beginning January 1, 2007, we were required to provide to residential electric customers a credit equal to the amount collected from all BGE electric customers for the decommissioning of Calvert Cliffs and to suspend collection of the residential return component of the administrative charge collected through residential standard offer service rates through May 31, 2007. Under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, we were required to reinstate collection of the residential return component of the administration charge in rates and to provide all residential electric customers a credit for the residential return component of the administrative charge. Under the 2008 Maryland settlement agreement, BGE was allowed to resume collection of the residential return portion of the administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to residential customers. Beginning June 1, 2010, BGE has provided all residential customers a credit for the residential return portion of the administrative charge. This credit will be given to customers through December 31, 2016.

The increase in revenues attributable to a decrease in Senate Bill 1 Credits during the quarter ended June 30, 2011 compared to the same period in 2010 is primarily due to lower sales volumes, partially offset by the reinstatement of the rebate to customers for the residential return component of the administrative charge on June 1, 2010.

The decrease in revenues attributable to an increase in Senate Bill 1 Credits during the six months ended June 30, 2011 compared to the same periods in 2010 is primarily due to the reinstatement of the rebate to customers for the residential return component of the administrative charge on June 1, 2010, partially offset by lower volumes.

Electricity Purchased for Resale Expenses

Electricity purchased for resale expenses include the cost of electricity purchased for resale to our standard offer service customers. These costs do not include the cost of electricity purchased by delivery service only customers. The following

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table summarizes our regulated electricity purchased for resale expenses:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	2010	**2011**	2010
	(In millions)			
Actual costs	**$ 261.8**	$ 387.8	**$ 602.3**	$ 845.9
Recovery under rate stabilization plan	**10.9**	13.6	**24.3**	29.1
Electricity purchased for resale expenses	**$ 272.7**	$ 401.4	**$ 626.6**	$ 875.0

Actual Costs

BGE's actual costs for electricity purchased for resale decreased $126.0 million and $243.6 million during the quarter and six months ended June 30, 2011 compared to the same periods of 2010, primarily due to lower contract prices to purchase electricity for our customers and lower volumes due to an increase in customers using competitive suppliers.

Recovery Under Rate Stabilization Plan

BGE deferred electricity purchased for resale expenses representing the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under our rate stabilization plan. These deferred expenses, plus carrying charges, are included in "Regulatory Assets (net)" in our, and BGE's, Consolidated Balance Sheets.

We recovered $10.9 million and $24.3 million of this amount in the quarter and six months ended June 30, 2011.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $9.2 million in the quarter ended June 30, 2011 compared to the same period in 2010, primarily due to higher labor and benefits costs and the impact of inflation.

Regulated electric operations and maintenance expenses increased $8.3 million in the six months ended June 30, 2011 compared to the same period in 2010, primarily due to higher labor and benefits costs and the impact of inflation. This increase is offset by a first quarter $15.1 million reduction to 2011 operations and maintenance expenses due to incremental distribution service restoration expenses associated with 2010 storms and other costs that were deferred as regulatory assets in 2011 as required by the Maryland PSC in its comprehensive distribution rate order received in March 2011. This, however, was partially offset by $12.9 million in incremental distribution service restoration expenses associated with 2011 storms and $1.8 million in amortization associated with the new regulatory assets. We discuss the new regulatory assets in the *Notes to Consolidated Financial Statements* on page 13.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail on page 9 in *Notes to Consolidated Financial Statements*. However, BGE will not seek recovery of these costs in rates.

Electric Depreciation and Amortization

Regulated electric depreciation and amortization expense increased $5.8 million and $13.4 million during the quarter and six months ended June 30, 2011, compared to the same periods in 2010, primarily due to increased amortization of $4.6 million and $9.1 million, respectively, of deferred Smart Energy Savers Program^{SM} costs due to an increase in program surcharges, and increased property, plant and equipment depreciation of $2.4 million and $4.2 million, respectively.

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Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section of our 2010 Annual Report on Form 10-K.

Results

	Quarter Ended June 30, 2011	Quarter Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Revenues	**$ 109.1**	$ 100.4	**$ 416.4**	$ 418.4
Gas purchased for resale expenses	**(49.8)**	(42.1)	**(220.9)**	(236.6)
Operations and maintenance expenses	**(42.0)**	(39.1)	**(82.1)**	(74.3)
Merger costs	**(2.3)**		**(2.3)**	
Depreciation and amortization	**(11.4)**	(11.0)	**(23.7)**	(22.3)
Taxes other than income taxes	**(8.2)**	(8.1)	**(19.0)**	(18.5)
(Loss) Income from operations	**$ (4.6)**	$ 0.1	**$ 68.4**	$ 66.7
Net (Loss) Income	**$ (6.3)**	$ (3.9)	**$ 35.1**	$ 33.3
Net (Loss) Income attributable to common stock	**$ (7.2)**	$ (4.7)	**$ 33.4**	$ 31.8
Other Items Included in Operations (after-tax):				
Merger costs[1]	**$ (1.4)**	$	**$ (1.4)**	$

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

1 BGE will not seek recovery of these costs in rates.

Gas Revenues

The changes in gas revenues during the quarter and six months ended June 30, 2011 compared to the same periods of 2010 were caused by:

	Quarter Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
	(In millions)	
Distribution volumes	$ 5.7	$ 14.9
Base rates	(0.5)	6.6
Gas revenue decoupling	(5.3)	(12.7)
Gas cost adjustments	2.1	(16.7)
Total change in gas revenues from gas system sales	2.0	(7.9)
Off-system sales	6.5	5.3

Other		0.2		0.6
Total change in gas revenues	$	8.7	$	(2.0)

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, during the quarter and six months ended June 30, 2011 compared to the same periods of 2010 were:

	Quarter Ended June 30, 2011 vs. 2010	**Six Months Ended June 30, 2011 vs. 2010**
Residential	6.8%	2.5%
Commercial	16.5	11.3
Industrial	(31.1)	(33.5)

During the quarter and six months ended June 30, 2011 compared to the same periods in 2010, we distributed more gas to residential customers, mostly due to increased usage per customer and an increased number of customers, partially offset by milder weather. We distributed more gas to commercial customers compared to the same periods of 2010, mostly due to increased usage per customer and an increased number of customers. We distributed less gas to industrial customers compared to the same periods of 2010, mostly due to decreased usage per customer.

Base Rates

On December 6, 2010, the Maryland PSC authorized BGE to increase gas distribution rates by $9.8 million for service rendered on or after December 4, 2010. This increase was based upon a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio. We discuss BGE's gas base rates in *Notes to Consolidated Financial Statements* on page 13.

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Gas Revenue Decoupling

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather and usage patterns per customer on our gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1* of our 2010 Annual Report on Form 10-K. However, under the market-based rates mechanism approved by the Maryland PSC, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

Customers who do not purchase gas from BGE are not subject to the gas cost adjustment clauses because we are not selling gas to them. However, these customers are charged base rates to recover the costs BGE incurs to deliver their gas through our distribution system, and are included in the gas distribution volume revenues.

Gas cost adjustment revenues increased $2.1 million during the quarter ended June 30, 2011, compared to the same period of 2010, mostly because we sold more gas at higher rates.

Gas cost adjustment revenues decreased $16.7 million during the six months ended June 30, 2011, compared to the same period of 2010, because we sold less gas at lower rates.

Off-System Gas Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Off-system gas sales, which occur after we have satisfied our customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders). Changes in off-system sales do not significantly impact earnings.

Revenues from off-system gas sales increased during the quarter and six months ended June 30, 2011 compared to the same periods of 2010, primarily due to higher volumes, partially offset by lower prices.

Gas Purchased For Resale Expenses

Gas purchased for resale expenses include the cost of gas purchased for resale to our customers and for off-system sales. These costs do not include the cost of gas purchased by delivery service only customers.

Gas costs increased $7.7 million during the quarter ended June 30, 2011 compared to the same period of 2010 because we purchased more gas at higher prices.

Gas costs decreased $15.7 million during the six months ended June 30, 2011 compared to the same period of 2010 because we purchased gas at lower prices, partially offset by higher volumes of gas purchased.

Gas Operations and Maintenance Expenses

Regulated gas operation and maintenance expenses increased $2.9 million and $7.8 million in the quarter and six months ended June 30, 2011 compared to the same period in 2010, primarily due to higher labor and benefits costs and the impact of inflation.

Merger Costs

We discuss costs related to the proposed merger with Exelon in more detail on page 9 in *Notes to Consolidated Financial Statements*. However, BGE will not seek recovery of these costs in rates.

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Other Nonregulated Businesses

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Revenues	**$ 0.5**	$ 0.1	**$**	$ 0.1
Operating expense	**11.1**	13.4	**22.5**	29.1
Depreciation and amortization	**(10.7)**	(12.2)	**(21.4)**	(26.1)
Taxes other than income taxes	**(0.7)**	(1.3)	**(1.4)**	(2.2)
Gain on divestitures		0.1		0.1
Income (Loss) from Operations	**$ 0.2**	$ 0.1	**$ (0.3)**	$ 1.0
Net (Loss) Income	**$ (1.1)**	$ 0.7	**$ (4.2)**	$ (3.6)
Net (Loss) Income attributable to common stock	**$ (1.1)**	$ 0.7	**$ (4.2)**	$ (3.6)
Other Items Included in Operations (after-tax):				
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$**	$	**$**	$ (4.8)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Consolidated Nonoperating Income and Expenses

Other Expense

Other expense increased $6.8 million during the quarter ended June 30, 2011 compared to the same period of 2010 mostly due to a lower level of interest income as a result of a lower average cash balance outstanding.

Fixed Charges

Our fixed charges increased during the quarter ended June 30, 2011 compared to the same period of 2010 mostly due to a higher level of interest expense as a result of a higher average debt balance outstanding.

Our fixed charges decreased during the six months ended June 30, 2011 compared to the same period of 2010 mostly due to the absence in 2011 of a $50.1 million loss recognized in February 2010 on the retirement of $486.5 million of our 7.00% Notes due April 1, 2012, partially offset by a higher average debt balance outstanding.

Fixed charges at BGE decreased during the six months ended June 30, 2011 compared to the same period of 2010 primarily due to lower level of interest expense due to repayments of debt.

Income Taxes

Income tax expense increased $35.8 million during the quarter ended June 30, 2011 compared to the same period of 2010 primarily due to higher income before income taxes in 2011 and a higher effective tax rate.

Income tax expense decreased $9.7 million during the six months ended June 30, 2011 compared to the same period of 2010 primarily due to lower income before income taxes in 2011, partially offset by a higher effective tax rate.

We discuss changes to our effective tax rate on page 17 in *Notes to Consolidated Financial Statements*.

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Financial Condition

Cash Flows

The following table summarizes our cash flows for the six months ended June 30, 2011 and 2010.

	2011 Segment Cash Flows				Consolidated Cash Flows	
	Six Months Ended June 30, 2011				Six Months Ended June 30,	
	Generation	NewEnergy	Regulated	Eliminations, Holding Company and Other	2011	2010
	(In millions)					
Operating Activities						
Net income (loss)	$ 53.7	$ 40.3	$ 97.7	$ (4.2)	$ 187.5	$ 275.1
Derivative contracts classified as financing activities[1]		6.7			6.7	79.8
Gain on DOE settlement	(35.5)				(35.5)	
Other non-cash adjustments to net income (loss)	273.4	147.5	207.6	17.5	646.0	396.2
Changes in working capital						
Derivative assets and liabilities, excluding collateral	8.4	315.4	0.1		323.9	227.3
Net collateral and margin		(47.9)	1.2		(46.7)	(73.4)
Accrued taxes	75.2	(29.0)	20.2	(33.7)	32.7	(826.2)
Other changes	(3.1)	(292.9)	163.3	35.0	(97.7)	(287.9)
Defined benefit obligations[2]					19.0	(5.3)
Other	(73.3)	35.6	(46.0)	24.3	(59.4)	7.8
Net cash provided by (used in) operating activities	298.8	175.7	444.1	38.9	976.5	(206.6)
Investing activities						
Investments in property, plant and equipment	(59.2)	(191.4)	(304.6)	(11.1)	(566.3)	(425.0)
Asset and business acquisitions, net of cash acquired	(1,084.0)	(145.6)			(1,229.6)	(372.9)
Change in cash pool	1,003.5	211.7		(1,215.2)		
Proceeds from DOE grant			28.3		28.3	
Proceeds from sale of investments and other assets						21.2
Proceeds from investment tax credits and grants related to renewable energy investments	0.4	36.9			37.3	21.5
Payment for issuance of loans receivable	(15.0)				(15.0)	
Contract and portfolio acquisitions		(3.7)			(3.7)	(29.0)
Decrease (Increase) in restricted funds	50.0	3.6	4.3		57.9	(30.0)
Other investments	(6.7)	(2.3)			(9.0)	(0.7)
Net cash used in investing activities	(111.0)	(90.8)	(272.0)	(1,226.3)	(1,700.1)	(814.9)
Cash flows from operating activities plus cash flows from investing activities	$ 187.8	$ 84.9	$ 172.1	$ (1,187.4)	(723.6)	(1,021.5)

Financing Activities[2]		
Net repayment of debt	(255.5)	(646.0)
Proceeds from issuance of common stock	11.3	8.8
Debt and credit facility costs	(3.2)	(0.7)
Common stock dividends paid	(91.9)	(92.6)
BGE preference stock dividends paid	(6.6)	(6.6)
Proceeds from contract and portfolio acquisitions	1.0	2.3
Derivative contracts classified as financing activities[1]	(6.7)	(79.8)
Other	1.5	(0.7)
Net cash used in financing activities	(350.1)	(815.3)
Net decrease in cash and cash equivalents	$ (1,073.7)	$ (1,836.8)

1 All ongoing cash flows from derivative contracts deemed to contain a financing element at inception must be reclassified from operating activities to financing activities.

2 Items are not allocated to the business segments because they are managed for the company as a whole.

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Cash Flows from Operating Activities

In the six months ended June 30, 2011, cash provided by operating activities was $1.0 billion, reflecting $0.4 billion of cash inflows from our regulated business and $0.5 billion of cash inflows from our competitive businesses.

The $1.2 billion increase in operating cash flows for the six months ended June 30, 2011 compared to the same period of 2010 is primarily due to:

- $1.0 billion of lower income tax payments, most of which related to the federal taxes paid in 2010 associated with the EDF transaction that closed in November 2009, and
- $0.1 billion related to changes in net derivative assets and liabilities. Changes in derivative assets and liabilities are driven by fluctuations in commodity prices and the realization of contracts at settlement within our NewEnergy business.

The change in net collateral and margin for the six months ended June 30, 2011 as compared to the same period in 2010 was as follows:

	June 30, 2011	June 30, 2010
	(In millions)	
Net collateral and margin held, January 1,	**$ 121.4**	$ 77.2
Additional / (return of) collateral held associated with nonderivative contracts	**4.8**	(9.2)
Net return of collateral posted associated with nonderivative contracts	**1.4**	2.9
(Additional) / return of initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	**(81.4)**	0.9
Return of / (additional) fair value net cash collateral held (posted) (netted against derivative assets / liabilities)*	**28.5**	(68.0)
Change in net collateral and margin posted	**(46.7)**	(73.4)
Net collateral and margin held, June 30,	**$ 74.7**	$ 3.8

** We discuss our netting of fair value collateral with our derivative assets / liabilities in more detail in Note 13 to Consolidated Financial Statements of our 2010 Annual Report on Form 10-K.*

We discuss all forms of collateral in terms of their impact on our business in the *Collateral* section.

Cash Flows from Investing Activities

Cash used in investing activities for the six months ended June 30, 2011 was $1.7 billion, compared to $0.8 billion used in the six months ended June 30, 2010. The $0.9 billion increase from the prior year was due primarily to the acquisition of Boston Generating's 2,950 MW fleet of generating plants in January 2011 and the acquisition of StarTex in May 2011.

Cash Flows from Financing Activities

Cash used in financing activities was $0.4 billion in the six months ended June 30, 2011, compared to cash used in financing activities of $0.8 billion in the six months ended June 30, 2010. The $0.4 billion decrease in cash used in financing activities was primarily due to lower net debt repayments in the first half of 2011 compared to the same period in 2010. In 2011, we repaid $0.2 billion of 7.00% Notes due April 1, 2012. In 2010, we retired $0.5 billion of 7.00% Notes due April 1, 2012 pursuant to a cash tender offer and repurchased outstanding tax exempt notes totaling $0.1 billion.

Available Sources of Funding

In addition to cash generated from operations, we rely upon access to capital for our capital expenditure programs and for the liquidity required to operate and support our competitive businesses. Our liquidity requirements are funded by credit facilities and cash. We fund our short-term working capital needs with existing cash and with our credit facilities, many of which support direct cash borrowings and the issuance of commercial paper. We also use our credit facilities to support the issuance of letters of credit, primarily for our NewEnergy business.

The primary drivers of our use of liquidity have been our capital expenditure requirements and collateral requirements associated with hedging our generating assets and hedging our NewEnergy business in both power and gas. Significant changes in the prices of commodities, depending on hedging strategies we have employed, could require us to post additional letters of credit, and thereby reduce the overall amount available under our credit facilities or to post additional cash, thereby reducing our available cash balance. Additional regulation of the derivatives markets could also require us to post additional cash collateral. We discuss the financial reform legislation enacted in 2010 in more detail in *Item 7. Management's Discussion and Analysis Federal Regulation* section of our 2010 Annual Report on Form 10-K.

We discuss our, and BGE's, credit facilities in detail beginning on page 15 of the *Notes to the Consolidated Financial Statements*.

Net Available Liquidity

Constellation Energy's (excluding BGE) and BGE's net available liquidity at June 30, 2011 was $3.2 billion and $0.7 billion, respectively. We discuss net available liquidity

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in more detail in the *Notes to Consolidated Financial Statements* on page 17.

Collateral

Constellation Energy's collateral requirements generally arise from the needs of its NewEnergy business as a result of its participation in certain organized markets, such as Independent System Operators (ISOs) or financial exchanges, as well as from its margining on over-the-counter (OTC) contracts.

We discuss our uses of collateral in our businesses as well as the inherent asymmetries relating to the use of collateral that create liquidity requirements for our Generation and NewEnergy businesses in *Item 7. Management's Discussion and Analysis* of our 2010 Annual Report on Form 10-K.

Customers of our NewEnergy business rely on the creditworthiness of Constellation Energy. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade in the senior unsecured debt of Constellation Energy. Based on contractual provisions at June 30, 2011, we estimate that if Constellation Energy's senior unsecured debt were downgraded to one level below the investment grade threshold we would have the following additional collateral obligations:

Credit Ratings Downgraded to[1]	Level Below Current Rating	Additional Obligations[2]
		(In billions)
Below investment grade	1	$ 1.1

1 If there are split ratings among the independent credit-rating agencies, the lowest credit rating is used to determine our incremental collateral obligations.

2 Includes $0.1 billion related to derivative contracts as discussed in Notes to Consolidated Financial Statements on page 31.

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post additional collateral in an amount that could exceed the obligation amounts specified above, which could be material. We discuss our credit facilities in the *Notes to Consolidated Financial Statements* beginning on page 15.

Capital Resources

Our estimated annual cash requirement amounts for the years 2011 and 2012 are shown in the table below.

We will continue to have cash requirements for:

- working capital needs,
- payments of interest, distributions, and dividends,
- capital expenditures, and
- the retirement of debt.

Capital requirements for 2011, 2012, and 2013 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

- regulation, legislation, and competition,
-

- BGE load requirements,
- environmental protection standards,
- the type and number of projects selected for construction or acquisition,
- the effect of economic and market conditions on those projects,
- the cost and availability of capital,
- potential capital contributions to CENG,
- the availability of cash from operations, and
- business decisions to invest in capital projects.

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section on page 64 and *Risk Factors* section beginning on page 60 and in our 2010 Annual Report on Form 10-K. We discuss the potential impact of environmental legislation and regulation in more detail on page 38 and in *Item 1. Business Environmental Matters* section of our 2010 Annual Report on Form 10-K.

Calendar Year Estimates	**2011**	**2012**
	(In billions)	
Generation and Other Capital Requirements:		
Major Environmental	$ 0.1	$
Maintenance	0.1	0.1
Growth		
Total Generation and Other Capital Requirements	0.2	0.1
NewEnergy Capital Requirements:		
Maintenance		
Growth	0.3	0.2
Total NewEnergy Capital Requirements	0.3	0.2
Regulated Capital Requirements:		
Electric/Gas Distribution	0.4	0.4
Electric Transmission	0.1	0.1
Smart Energy Savers^{SM} Initiatives	0.1	0.2
Total Regulated Capital Requirements	0.6	0.7
Total Capital Requirements	$ 1.1	$ 1.0

Eligible capital projects are shown net of anticipated investment tax credits or grants.

As of the date of this report, we estimate our 2013 capital requirements will be approximately $1.2 billion.

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Capital Requirements

Generation and NewEnergy Businesses

Our Generation and NewEnergy businesses' capital requirements consist of its continuing requirements, including expenditures for:

- maintenance and uprates to the capacity of our generating plants,
- solar projects and upstream natural gas properties,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and various other states' environmental regulations and legislation, and
- enhancements to our information technology infrastructure.

In addition, in 2011, we made several acquisitions totaling approximately $1.4 billion. We funded these acquisitions primarily through available cash. We discuss these acquisitions in more detail in the *Notes to Consolidated Financial Statements* beginning on page 11.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability and support demand response and conservation initiatives. Further, BGE continues to invest in transmission projects that earn a FERC authorized rate of return.

In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of approximately $480 million. In 2009, the United States Department of Energy (DOE) selected BGE as a recipient of $200 million in federal funding for our smart grid and other related initiatives. This grant allows BGE to be reimbursed for smart grid and other expenditures up to $200 million, substantially reducing the total cost of these initiatives.

Funding for Capital Requirements

We discuss our funding for capital requirements in our 2010 Annual Report on Form 10-K.

Contractual Payment Obligations and Committed Amounts

We enter into various agreements that result in contractual payment obligations in connection with our business activities. These obligations primarily relate to our financing arrangements (such as long-term debt, preference stock, and operating leases), purchases of capacity and energy to support our Generation and NewEnergy business activities, and purchases of fuel and transportation to satisfy the fuel requirements of our power generating facilities.

We detail our contractual payment obligations at June 30, 2011 in the following table:

	Payments				
	2011	2012-2013	2014-2015	There-after	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$	$ 11.6	$ 606.8	$ 1,782.5	$ 2,400.9
Interest	67.1	273.7	276.5	2,883.8	3,501.1

Total	67.1	285.3	883.3	4,666.3	5,902.0
BGE					
Principal	52.0	639.1	144.9	1,277.9	2,113.9
Interest	63.5	231.3	162.5	1,174.2	1,631.5
Total	115.5	870.4	307.4	2,452.1	3,745.4
BGE preference stock				190.0	190.0
Operating leases[2]					
Operating leases, gross	148.5	443.9	436.4	198.4	1,227.2
Sublease rentals	(0.2)	(0.1)			(0.3)
Operating leases, net	148.3	443.8	436.4	198.4	1,226.9
Purchase obligations:[3]					
Purchased capacity and energy[4]	273.8	601.4	219.7	299.0	1,393.9
Purchased energy from CENG[5]	264.1	1,725.3	1,666.5		3,655.9
Fuel and transportation	355.7	687.1	229.4	179.2	1,451.4
Other	257.0	85.2	48.0	114.2	504.4
Other noncurrent liabilities:					
Uncertain tax positions liability	53.7	100.7	9.2	4.5	168.1
Pension benefits[6]	4.8	69.8	183.0		257.6
Postretirement and post employment benefits[7]	16.1	55.5	58.5	265.3	395.4
Total contractual payment obligations	$ 1,556.1	$ 4,924.5	$ 4,041.4	$ 8,369.0	$ 18,891.0

1 Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $75.0 million early through remarketing features. Interest on variable rate debt is included based on forward curve for interest rates.

2 Our operating lease commitments include future payment obligations under certain power purchase agreements as discussed further in Note 11 of our 2010 Annual Report on Form 10-K.

3 Contracts to purchase goods or services that specify all significant terms. Amounts related to certain purchase obligations are based on future purchase expectations which may differ from actual purchases.

4 Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements.

5 As part of reaching a comprehensive agreement with EDF in October 2010, we modified our existing power purchase agreement with CENG to be unit contingent through the end of its original term in 2014. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, we agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. We have included in the table our commitments under this agreement for five years, the time period for which we have more reliable data. Further, we continue to own a 50.01% membership interest in CENG that we account for as an equity method investment. See Note 16 of our 2010 Annual Report on Form 10-K for more details on this agreement.

6 Amounts related to pension benefits reflect our current 5-year forecast for contributions for our qualified pension plans and participant payments for our nonqualified pension plans. Refer to Note 7 of our 2010 Annual Report on Form 10-K for more detail on our pension plans.

7 Amounts related to postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded in our Consolidated Balance Sheets as discussed in Note 7 of our 2010 Annual Report on Form 10-K.

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Off-Balance Sheet Arrangements

We discuss our off-balance sheet arrangements in our 2010 Annual Report on Form 10-K.

At June 30, 2011, Constellation Energy had a total face amount of $9.6 billion in guarantees outstanding, of which $8.8 billion related to our Generation and NewEnergy businesses. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was $1.5 billion at June 30, 2011, which represents the total amount the parent company could be required to fund based on June 30, 2011 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets. We believe it is unlikely that we would be required to perform or incur any losses associated with guarantees of our subsidiaries' obligations.

We discuss our other guarantees in the *Notes to Consolidated Financial Statements* beginning on page 18.

Risk Management

Market Risk

Economic Value at Risk (EVaR)

EVaR measures the potential pre-tax loss in the fair value of the Generation and NewEnergy businesses due to changes in market risk factors. EVaR is a one-day value-at-risk measure calculated at a 95% confidence level assuming a standard normal distribution of prices over the most recent rolling 3-month period. EVaR includes all positions over a forward rolling 60-month time horizon that expose us to market price risk, regardless of accounting treatment and business line.

Positions included in EVaR are comprised of mark-to-market and nonderivative accrual positions that create market risk including:

- derivative and nonderivative commodity contracts associated with our Generation and NewEnergy businesses,
- physical assets, such as our owned and contractually controlled generating plants,
- our share of investments in generating plants, and
- our share of investments in upstream natural gas properties.

We include the positions related to physical assets to provide a more complete presentation of our commodity market risk exposures. EVaR includes illiquid products and positions for which there is limited price discovery. Modeling the positions in our Generation and NewEnergy businesses involves a number of assumptions, and includes projections of generation, emission rates and costs, customer load growth, load response to weather, and customer response to competitive supply. Changes in our forecast or management estimates will affect the fair value of these positions in a manner not captured by EVaR.

EVaR reflects the risk of loss due to market prices under normal market conditions. An inherent limitation of our value-at-risk measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from the past. We use stress tests and scenario analysis to better understand extreme events as a complement to EVaR. This includes exposure to unlikely but plausible events in abnormal markets, sensitivity to changes in management projections of customer demand or forecasted generation output, and price sensitivity to illiquid points and regional basis spreads.

EVaR is monitored daily and is subject to regional and overall guidelines for the NewEnergy business. We place guidelines on the risk associated with illiquid delivery locations and regional basis within our NewEnergy business. Additionally, we monitor generation plant hedge ratios relative to guidelines specified by management. Stress tests and scenario analysis are conducted regularly and the results, trends, and explanations are reviewed by senior management and risk committees.

The EVaR amounts below represent the potential pre-tax change in the fair values of our Generation and NewEnergy businesses positions over a one-day holding period.

EVaR	**Quarter Ended June 30, 2011**
	(In millions)
95% Confidence Level, One-Day Holding Period	
Quarter end	$ 47.0
Average	53.3
High	61.3
Low	45.0

Value at Risk (VaR)

VaR measures the potential pre-tax loss in the fair value of the mark-to-market energy contracts due to changes in market risk factors. VaR is calculated assuming a standard normal distribution of prices over the most recent rolling 3-month period. VaR includes all positions subject to mark-to-market accounting, including contracts that hedge the economics of NewEnergy nonderivative power and fuel contracts, which do not receive hedge accounting treatment, and contracts designated for trading. Thus, the positions for which we monitor VaR are included within, and are not incremental, to the positions subject to EVaR.

VaR and EVaR have similar limitations. VaR may include some products and positions for which there is limited price discovery or market depth. The modeling of option positions included in VaR involves a number of assumptions and approximations. An inherent limitation of our VaR measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from that of the past.

The VaR amounts below represent the potential pre-tax loss in the fair value of our Generation and NewEnergy businesses positions subject to mark-to-market accounting, including both trading and non-trading activities, over one and ten-day holding periods. We experienced higher average VaR for the quarter ended June 30, 2011, primarily as a result of executing contracts to reduce risk in our NewEnergy business that do not receive hedge accounting treatment.

Total Mark-to-Market VaR	**Quarter Ended June 30, 2011**
	(In millions)
99% Confidence Level, One-Day Holding Period	
Quarter end	$ 22.4
Average	17.3
High	27.3
Low	10.2
95% Confidence Level, One-Day Holding Period	
Quarter end	17.0
Average	13.2
High	20.8
Low	7.8
95% Confidence Level, Ten-Day Holding Period	
Quarter end	53.8
Average	41.7
High	65.7
Low	24.6

Wholesale Credit Risk

We measure wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual) adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff. We monitor and manage the credit risk of our NewEnergy business through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral, or prepayment arrangements, and the use of master netting agreements.

As of June 30, 2011, our total exposure across our entire wholesale portfolio was $2.0 billion, net of collateral, and includes accrual positions and derivatives. This total exposure has declined from the $2.5 billion as of December 31, 2010, primarily driven by a change in commodity prices.

The top ten counterparties account for 50% of our total exposure with 3% of that exposure being non-investment grade. We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of total credit exposure. As of June 30, 2011, we had a total exposure of 14% to one counterparty, a large power cooperative.

As of June 30, 2011 and December 31, 2010, counterparties in our credit portfolio had the following public credit ratings:

	June 30, 2011	**December 31, 2010**
Rating		
Investment Grade[1]	**51%**	47%
Non-Investment Grade	**3**	4

Not Rated	**46**	49

1 Includes counterparties with an investment grade rating by at least one of the major credit rating agencies. If split rating exists, the lower rating is used.

Our exposure to "Not Rated" counterparties was $0.9 billion at June 30, 2011 compared to $1.2 billion at December 31, 2010. This decrease was mostly driven by a reduction in our credit exposure with CENG and two large power companies.

Many of our not rated counterparties (including CENG) are considered investment grade equivalent based on our internal credit ratings. We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. Based on internal credit ratings, approximately $0.8 billion or 86% of the exposure to "Not Rated" counterparties was rated investment grade equivalent at June 30, 2011 and approximately $1.1 billion or 87% was rated investment grade equivalent at December 31, 2010.

The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings. This includes those counterparties which are externally rated and those in the "Not Rated" category as a percentage of the total portfolio exposure.

	June 30, 2011	**December 31, 2010**
Investment Grade Equivalent	91%	89%
Non-Investment Grade	9	11

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If a counterparty were to default on its contractual obligations and we were to liquidate transactions with that entity, our potential credit loss would include all forward and settlement exposure plus any additional costs related to termination and replacement of the positions. This would include contracts accounted for using the mark-to-market, hedge, and accrual accounting methods, the amount owed or due from settled transactions, less any collateral held from the counterparty. In addition, if a counterparty were to default under an accrual contract that is currently favorable to us, we may recognize a material adverse impact on our results in the future delivery period to the extent that we are required to replace the contract that is in default with another contract at current market prices. These potential losses would be limited to the extent that the in-the-money amount exceeded any credit mitigants such as cash, letters of credit, or parental guarantees supporting the counterparty obligation. To reduce our credit risk with counterparties, we attempt to enter into agreements that allow us to obtain collateral on a contingent basis, seek third party guarantees of the counterparty's obligation, and enter into netting agreements that allow us to offset receivables and payables with forward exposure across many transactions.

Due to volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract (for example, fail to deliver the power we had contracted for), we could incur a loss that could have a material impact on our financial results.

We also enter into various wholesale transactions through ISOs. These ISOs are exposed to counterparty credit risks. Any losses relating to counterparty defaults impacting the ISOs are allocated to and borne by all other market participants in the ISO. These ISOs have established credit policies and practices to mitigate the exposure of counterparty credit risks. As a market participant, we continuously assess our exposure to the credit risks of each ISO.

BGE is exposed to wholesale credit risk of its suppliers for electricity and gas to serve its retail customers. BGE may receive performance assurance collateral to mitigate electricity suppliers' credit risks in certain circumstances. Performance assurance collateral is designed to protect BGE's potential exposure over the term of the supply contracts and will fluctuate to reflect changes in market prices. In addition to the collateral provisions, there are supplier "step-up" provisions, where other suppliers can step in if the early termination of a full-requirements service agreement with a supplier should occur, as well as specific mechanisms for BGE to otherwise replace defaulted supplier contracts. All costs incurred by BGE to replace the supply contract are to be recovered from the defaulting supplier or from customers through rates.

Interest Rate Risk, Retail Credit Risk, Foreign Currency Risk, Security Price Risk, Operational Risk and Collateral and Funding Liquidity Risk

We discuss our exposure to interest rate risk, retail credit risk, foreign currency risk, security price risk, operational risk, and collateral and funding liquidity risk in the *Risk Management* section of our 2010 Annual Report on Form 10-K.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We discuss the following information related to our market risk:

- hedging activities in the *Notes to Consolidated Financial Statements* beginning on page 22,
- activities of our Generation and NewEnergy businesses in their respective section of *Management's Discussion and Analysis* beginning on page 40,
- evaluation of commodity and credit risk in the *Risk Management* section of *Management's Discussion and Analysis* beginning on page 56, and
- changes to our business environment in the *Business Environment* section of *Management's Discussion and Analysis* beginning on page 37.

Item 4. Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Constellation Energy or BGE have been detected. These inherent limitations include errors by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures

The principal executive officer and principal financial officer of Constellation Energy have each evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal quarter covered by this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in the reports that Constellation Energy files and submits under the Exchange Act is recorded, processed, summarized, and reported when required and is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosure.

The principal executive officer and principal financial officer of BGE have each evaluated the effectiveness of the disclosure controls and procedures as of the Evaluation Date. Based on such evaluation, such officers have concluded that, as of the Evaluation Date, BGE's disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in the reports that BGE files and submits under the Exchange Act is recorded, processed, summarized, and reported when required and is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2011, there has been no change in either Constellation Energy's or BGE's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, either Constellation Energy's or BGE's internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We discuss our Legal Proceedings in the *Notes to Consolidated Financial Statements* beginning on page 20.

Item 1A. Risk Factors

You should consider carefully the following risks related to our proposed merger with Exelon, along with the risks described under Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K and the other information contained in this Form 10-Q. The risks and uncertainties described below and in our 2010 Annual Report on Form 10-K are not the only ones that may affect us. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 2. Management's Discussion and Analysis. If any of the following events occur, our business and financial results could be materially adversely affected.

Because the market price of shares of Exelon common stock will fluctuate and the exchange ratio will not be adjusted to reflect such fluctuations, the merger consideration at the date of the closing may vary significantly from the date the merger agreement was executed.

Upon completion of the merger, each outstanding share of Constellation Energy common stock will be converted into the right to receive 0.930 of a share of Exelon common stock. The number of shares of Exelon common stock to be issued pursuant to the merger agreement for each share of Constellation Energy common stock will not change to reflect changes in the market price of Exelon or Constellation Energy common stock. The market price of Exelon common stock at the time of completion of the merger may vary significantly from the market prices of Exelon common stock on the date the merger agreement was executed.

In addition, we might not complete the merger until a significant period of time has passed after the respective special shareholder meetings. Because Exelon will not adjust the exchange ratio to reflect any changes in the market value of Exelon common stock or Constellation Energy common stock, the market value of the Exelon common stock issued in connection with the merger and the Constellation Energy common stock surrendered in connection with the merger may be higher or lower than the values of those shares on earlier dates. Stock price changes may result from market reaction to the announcement of the merger and market assessment of the likelihood that the merger will be completed, changes in the business, operations or prospects of Exelon or Constellation Energy prior to or following the merger, litigation or regulatory considerations, general business, market, industry or economic conditions and other factors both within and beyond the control of Exelon and Constellation Energy. Neither we nor Exelon is permitted to terminate the merger agreement solely because of changes in the market price of either company's common stock.

The merger agreement contains provisions that limit each of Exelon's and Constellation Energy's ability to pursue alternatives to the merger, which could discourage a potential acquirer of either Constellation Energy or Exelon from making an alternative transaction proposal and, in certain circumstances, could require Exelon or Constellation Energy to pay to the other a significant termination fee.

Under the merger agreement, we and Exelon are restricted, subject to limited exceptions, from entering into alternative transactions in lieu of the merger. In general, unless and until the merger agreement is terminated, both we and Exelon are restricted from, among other things, soliciting, initiating, knowingly encouraging or facilitating a competing acquisition proposal from any person. Each of the Exelon board of directors and the Constellation Energy board of directors is limited in its ability to change its recommendation with respect to the merger-related proposals. We or Exelon may terminate the merger agreement and enter into an agreement with respect to a superior proposal only if specified conditions have been satisfied, including compliance with the non-solicitation provisions of the merger agreement. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of Exelon or Constellation Energy from considering or proposing such an acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the consideration proposed to be received or realized in the merger, or might result in a potential competing acquirer proposing to pay a lower price than it would otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances. Under the merger agreement, in the event we or Exelon terminates the merger agreement to accept a superior proposal, or under certain other circumstances, we or Exelon, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to us and a termination fee of $200 million in the case of a termination fee payable by us to Exelon.

Exelon and Constellation Energy will be subject to various uncertainties and contractual restrictions while the merger is pending that may cause disruption and could adversely affect their financial results.

Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on us and/or Exelon. These uncertainties may impair our and/or Exelon's ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company, and could cause customers, suppliers and others who deal with us or Exelon to seek to change existing business relationships with us or Exelon. The pursuit of the merger and the preparation for the integration may also place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect our and/or Exelon's financial results.

In addition, the merger agreement restricts each of Exelon and Constellation Energy, without the other's consent, from making certain acquisitions and taking other specified actions while the merger is pending. These restrictions may prevent Exelon and/or Constellation Energy from pursuing otherwise attractive business opportunities and making other changes to their respective businesses prior to completion of the merger or termination of the merger agreement.

If completed, the merger may not achieve its anticipated results, and Exelon and Constellation Energy may be unable to integrate their operations in the manner expected.

We entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and Constellation Energy can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of each company's ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. The combined company's results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occur prior to the closing of the merger. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company's future business, financial condition, operating results and prospects.

Pending litigation against Exelon and Constellation Energy could result in an injunction preventing the completion of the merger or a judgment resulting in the payment of damages in the event the merger is completed and may adversely affect the combined company's business, financial condition or results of operations and cash flows following the merger.

We are aware of 12 purported class action lawsuits that plaintiffs have filed against us, each member of our board of directors, Exelon and Bolt Acquisition Corporation, a Maryland corporation and a wholly owned subsidiary of Exelon, in connection with the merger. Among other things, the lawsuits seek injunctive relief that would prevent completion of the merger in accordance with the terms of the merger agreement. The outcome of any such litigation is uncertain. If a dismissal is not granted or a settlement is not reached, these lawsuits could prevent or delay completion of the merger and result in substantial costs to us and Exelon, including any costs associated with the indemnification of directors and officers. Plaintiffs may file additional lawsuits against us, Exelon, and/or the directors and officers of either company in connection with the merger. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition, results of operations and cash flows.

The merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the merger.

Completion of the merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission (NRC), the Federal Communications Commission, and the public utility commissions or similar entities in certain states in which the companies operate, including the Maryland PSC. The merger is also subject to review by the Antitrust Division of the U.S. Department of Justice, under the Hart-Scott-Rodino Act, and the expiration or earlier termination of the waiting period (and any extension of the waiting period) applicable to the merger is a condition to closing the merger. The special meetings of the shareholders of Exelon and Constellation Energy at which the proposals required to complete the merger will be considered are expected to take place before all of the required regulatory approvals

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have been obtained and before all conditions to such approvals, if any, are known.

In this event, if the shareholder proposals required to complete the merger are approved, we and Exelon may subsequently agree to conditions without seeking further shareholder approval, even if such conditions could have an adverse effect on us, Exelon, or the combined company.

We cannot provide assurance that we and Exelon will obtain all required regulatory consents or approvals or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the merger. The merger agreement generally permits each party to terminate the merger agreement if the final terms of any of the required regulatory consents or approvals require (1) any action that involves divesting, holding separate or otherwise transferring control over any nuclear or hydroelectric or pumped-storage generation assets of the parties or any of their respective subsidiaries or affiliates; or (2) any action (including any action that involves divesting, holding separate or otherwise transferring control over base-load capacity), without including those actions proposed by the parties' mutually agreed-upon analysis of mitigation to address the increased market concentration resulting from the merger and the concessions announced by the parties in the press release announcing the merger agreement, which would, individually or in the aggregate, reasonably be expected to have a material adverse effect on either party. Any substantial delay in obtaining satisfactory approvals, receipt of proceeds from required divestitures in an amount substantially lower than anticipated or the imposition of any terms or conditions in connection with such approvals could cause a material reduction in the expected benefits of the merger. If any such delays or conditions are serious enough, the parties may decide to abandon the merger.

If completed, the merger may adversely affect the combined company's ability to attract and retain key employees.

Current and prospective Exelon and Constellation Energy employees may experience uncertainty about their future roles at the combined company following the completion of the proposed merger. In addition, current and prospective Exelon and Constellation Energy employees may determine that they do not desire to work for the combined company for a variety of possible reasons. These factors may adversely affect the combined company's ability to attract and retain key management and other personnel.

Failure to complete the merger could negatively affect our share price and our future business and financial results.

Completion of the merger is not assured and is subject to risks, including the risks that approval of the transaction by shareholders of Exelon and Constellation Energy or by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the merger is not completed, our ongoing business may be adversely affected and we will be subject to several risks, including:

- having to pay certain significant costs relating to the merger without receiving the benefits of the merger, including, in certain circumstances, a termination fee of $200 million to Exelon;
- the potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company;
- We will have been subject to certain restrictions on the conduct of our business, which may have prevented us from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger is pending; and
- our share price may decline to the extent that the current market prices reflect an assumption by the market that the merger will be completed.

Exelon and Constellation Energy may incur unexpected transaction fees and merger-related costs in connection with the merger.

We and Exelon expect to incur a number of non-recurring expenses, totaling approximately $144 million, associated with completing the merger, as well as expenses related to combining the operations of the two companies. The combined company may incur additional unanticipated costs in the integration of the businesses of Exelon and Constellation Energy. Although we expect that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Current Constellation Energy stockholders will have a reduced ownership and voting interest after the merger.

Exelon will issue or reserve for issuance approximately 201.9 million shares of Exelon common stock to Constellation Energy stockholders in the merger (including shares of Exelon common stock issuable pursuant to Constellation Energy stock options and other equity-based awards). Based on the number of shares of common stock of Exelon and Constellation Energy outstanding on March 31, 2011, upon the completion of the merger, former Constellation Energy stockholders would own approximately 22% of the outstanding shares of Exelon common stock immediately following the consummation of the merger.

Constellation Energy stockholders currently have the right to vote for our directors and on other matters affecting us. When the merger occurs, each Constellation

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Energy stockholder who receives shares of Exelon common stock will become a shareholder of Exelon with a percentage ownership of the combined company that will be smaller than the shareholder's percentage ownership of Constellation Energy.

As a result, former Constellation Energy stockholders will have less voting power in the combined company than they now have with respect to Constellation Energy.

Following the merger, Constellation Energy stockholders will own equity interests in a company that owns and operates a relatively higher proportion of nuclear generating facilities, which can present unique risks.

Exelon's ownership interest in and operation of a relatively higher proportion of nuclear facilities than Constellation Energy subjects Exelon to increased associated risks, including the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives; and costs associated with regulatory oversight by the NRC, including NRC imposed fines, lost revenues as a result of any NRC ordered shutdown of Exelon nuclear facilities, or increased capital costs as a result of increased NRC safety and security regulations, including any new requirements as a result of the NRC's review of the accident at the Fukushima nuclear power plant in Japan. As shareholders of Exelon following the merger, Constellation Energy stockholders may be adversely affected by these risks to a greater extent than they were prior to the merger.

Item 2. Issuer Purchases of Equity Securities

The following table discloses purchases of shares of our common stock made by us or on our behalf for the periods shown below.

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)
April 1 April 30, 2011	5,830	$ 30.69		
May 1 May 31, 2011	39	35.76		
June 1 June 30, 2011				
Total	5,869	$ 30.72		

1 Represents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock and restricted stock units.

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Item 5. Other Information

Forward Looking Statements

We make statements in this report that are considered forward looking statements within the meaning of the Securities Exchange Act of 1934. Sometimes these statements will contain words such as "believes," "anticipates," "expects," "intends," "plans," and other similar words. We also disclose non-historical information that represents management's expectations, which are based on numerous assumptions. These statements and projections are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance or achievements to be materially different from those we project. These risks, uncertainties, and factors include, but are not limited to:

- the timing and extent of changes in commodity prices and volatilities for energy and energy-related products including coal, natural gas, oil, electricity, nuclear fuel, and emission allowances, and the impact of such changes on our liquidity requirements,
- the liquidity and competitiveness of wholesale and retail markets for energy commodities,
- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and Baltimore Gas and Electric's (BGE) ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets,
- the ability to successfully identify, finance, and complete acquisitions and sales of businesses and assets, including generating facilities, and to successfully invest in new business initiatives and markets,
- the effect of weather and general economic and business conditions on energy supply, demand, prices, and customers' and counterparties' ability to perform their obligations or make payments,
- the ability to attract and retain customers in our NewEnergy business and to adequately forecast their energy usage,
- the timing and extent of customer choice and competition in the energy markets and the rules and regulations adopted in those markets,
- regulatory or legislative developments federally, in Maryland, or in other states that affect energy competition, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to safety, or environmental compliance,
- the ability of our regulated and nonregulated businesses to comply with complex and/or changing market rules and regulations,
- the ability of BGE to recover all its costs associated with providing customers service,
- operational factors affecting our generating facilities, BGE's transmission and distribution facilities, or our other commercial operations, including weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, acts of war, catastrophic events, and other events beyond our control,
- the impact of industry consolidation,
- the impact of increased energy conservation and use of renewable energy,
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the actual outcome of uncertainties associated with assumptions and estimates requiring judgment when managing our business, applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and, in the absence of verifiable market prices, the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),

- changes in accounting principles or practices,

- cost and other effects of legal and administrative proceedings and other events that may not be covered by insurance, including environmental liabilities and liabilities associated with catastrophic events, and

- the likelihood and timing of the completion of the pending merger with Exelon Corporation, the terms and conditions of any required regulatory approvals of the pending merger, and potential diversion of management's time and attention from our ongoing business during this time period.

Given these uncertainties, you should not place undue reliance on these forward looking statements. Please see the other sections of this report and our other periodic reports filed with the Securities and Exchange Commission (SEC) for more information on these factors. These forward looking statements represent our estimates and assumptions only as of the date of this report.

Changes may occur after that date, and neither Constellation Energy nor BGE assumes responsibility to update these forward looking statements.

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Item 6. Exhibits

Exhibit No. 10(a)*	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated.
Exhibit No. 10(b)*	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated.
Exhibit No. 12(a)	Constellation Energy Group, Inc. Computation of Ratio of Earnings to Fixed Charges.
Exhibit No. 12(b)	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Computation of Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements.
Exhibit No. 31(a)	Certification of Chairman of the Board, President and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(b)	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 31(d)	Certification of Chief Financial Officer and Treasurer of Baltimore Gas and Electric Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(a)	Certification of Chairman of the Board, President and Chief Executive Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(b)	Certification of Senior Vice President and Chief Financial Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(c)	Certification of President and Chief Executive Officer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 32(d)	Certification of Chief Financial Officer and Treasurer of Baltimore Gas and Electric Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit No. 101.INS	XBRL Instance Document
Exhibit No. 101.SCH	XBRL Taxonomy Extension Schema Document
Exhibit No. 101.PRE	XBRL Taxonomy Presentation Linkbase Document
Exhibit No. 101.LAB	XBRL Taxonomy Label Linkbase Document
Exhibit No. 101.CAL	XBRL Taxonomy Calculation Linkbase Document
Exhibit No. 101.DEF	XBRL Taxonomy Definition Linkbase Document

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** Compensatory plan*

In accordance with Rule 402 of Regulation S-T, the XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall not be deemed to be "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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SIGNATURE

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

CONSTELLATION ENERGY GROUP, INC

(Registrant)

Date: August 8, 2011

/s/ JONATHAN W. THAYER

Jonathan W. Thayer,
Senior Vice President of Constellation Energy Group, Inc. and as Principal Financial Officer

BALTIMORE GAS AND ELECTRIC COMPANY

(Registrant)

Date: August 8, 2011

/s/ CARIM V. KHOUZAMI

Carim V. Khouzami,
Chief Financial Officer of Baltimore Gas and Electric Company and as Principal Financial Officer