CONSTELLATION ENERGY GROUP INC
Form 10-Q
November 08, 2007

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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 **September 30, 2007**

Commission File Number	Exact name of registrant as specified in its charter	IRS Employer Identification No.
1-12869	**CONSTELLATION ENERGY GROUP, INC.**	**52-1964611**
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY**	**52-0280210**

MARYLAND
(State of Incorporation of both registrants)

750 E. PRATT STREET, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-783-2800

(Registrants' telephone number, including area code)

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. is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act.
(Check one):

Large accelerated filer ý Accelerated filer o Non-accelerated filer o

Indicate by check mark whether Baltimore Gas and Electric Company is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act.
(Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer ý

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 180,653,530 shares outstanding of Constellation Energy Group, Inc. on October 31, 2007.

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 1 FINANCIAL INFORMATION

Item 1 Financial Statements

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions, except per share amounts)			
Revenues				
Nonregulated revenues	**$ 4,965.4**	$ 4,631.8	**$ 13,332.1**	$ 12,307.0
Regulated electric revenues	**778.2**	649.9	**1,837.3**	1,652.6
Regulated gas revenues	**112.8**	111.7	**674.4**	671.8
Total revenues	**5,856.4**	5,393.4	**15,843.8**	14,631.4
Expenses				
Fuel and purchased energy expenses	**4,549.7**	4,096.2	**12,451.6**	11,415.5
Operating expenses	**653.6**	514.2	**1,802.7**	1,597.6
Impairment losses and other costs			**20.2**	
Workforce reduction costs		21.7	**2.3**	23.9
Merger-related costs		3.4		12.4
Depreciation, depletion, and amortization	**138.3**	136.4	**413.5**	399.9
Accretion of asset retirement obligations	**16.0**	17.0	**51.9**	50.2
Taxes other than income taxes	**73.7**	73.6	**219.7**	218.7
Total expenses	**5,431.3**	4,862.5	**14,961.9**	13,718.2
Income from Operations	**425.1**	530.9	**881.9**	913.2
Gains on Sale of CEP LLC Equity	**39.2**		**52.1**	
Other Income, primarily interest income	**29.1**	9.5	**116.7**	38.6
Fixed Charges				
Interest expense	**80.3**	83.1	**231.7**	239.3
Interest capitalized and allowance for borrowed funds used during construction	**(5.2)**	(3.5)	**(13.6)**	(10.0)
BGE preference stock dividends	**3.3**	3.3	**9.9**	9.9
Total fixed charges	**78.4**	82.9	**228.0**	239.2
Income from Continuing Operations Before Income Taxes	**415.0**	457.5	**822.7**	712.6
Income Tax Expense	**164.3**	151.2	**258.4**	230.6
Income from Continuing Operations	**250.7**	306.3	**564.3**	482.0
Income (loss) from discontinued operations, net of income taxes of $0.7, $10.1, $1.5 and $27.8, respectively	**0.7**	18.1	**(0.9)**	49.5
Net Income	**$ 251.4**	$ 324.4	**$ 563.4**	$ 531.5

		Three Months Ended September 30,				Nine Months Ended September 30,		
Earnings Applicable to Common Stock	**$**	**251.4**	$	324.4	**$**	**563.4**	$	531.5
Average Shares of Common Stock Outstanding Basic		**180.5**		179.7		**180.5**		179.1
Average Shares of Common Stock Outstanding Diluted		**182.8**		181.6		**182.8**		180.9
Earnings Per Common Share from Continuing Operations Basic	**$**	**1.39**	$	1.70	**$**	**3.13**	$	2.69
Income (loss) from discontinued operations				0.11		**(0.01)**		0.28
Earnings Per Common Share Basic	**$**	**1.39**	$	1.81	**$**	**3.12**	$	2.97
Earnings Per Common Share from Continuing Operations Diluted	**$**	**1.37**	$	1.69	**$**	**3.09**	$	2.66
Income (loss) from discontinued operations		**0.01**		0.10		**(0.01)**		0.28
Earnings Per Common Share Diluted	**$**	**1.38**	$	1.79	**$**	**3.08**	$	2.94
Dividends Declared Per Common Share	**$**	**0.435**	$	0.3775	**$**	**1.305**	$	1.1325

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

		Three Months Ended September 30,				Nine Months Ended September 30,		
		2007		**2006**		**2007**		**2006**
					(In millions)			
Net Income	**$**	**251.4**	$	324.4	**$**	**563.4**	$	531.5
Other comprehensive income (loss) (OCI)								
Hedging instruments:								
Reclassification of net loss on hedging instruments from OCI to net income, net of taxes		**275.1**		193.0		**833.4**		407.1
Net unrealized loss on hedging instruments, net of taxes		**(360.0)**		(369.7)		**(498.4)**		(1,418.7)
Available-for-sale securities:								
Reclassification of net gain on sales of securities from OCI to net income, net of taxes		**(0.5)**				**(3.3)**		(0.3)
Net unrealized (loss) gain on securities, net of taxes		**(13.0)**		16.7		**0.7**		20.0
Defined benefit obligations:								
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes		**5.8**				**18.3**		
Net unrealized gain (loss) on foreign currency, net of taxes		**3.3**		(0.3)		**6.4**		0.8
Comprehensive Income (Loss)	**$**	**162.1**	$	164.1	**$**	**920.5**	$	(459.6)

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	*September 30, 2007**	*December 31, 2006*
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 1,551.7**	$ 2,289.1
Accounts receivable (net of allowance for uncollectibles of **$45.9** and $48.9, respectively)	**3,642.8**	3,248.3
Fuel stocks	**510.9**	599.5
Materials and supplies	**208.9**	200.2
Mark-to-market energy assets	**963.8**	1,294.8
Risk management assets	**165.1**	261.7
Unamortized energy contract assets	**52.0**	35.2
Deferred income taxes	**220.8**	674.3
Other	**514.4**	497.0
Total current assets	**7,830.4**	9,100.1
Investments and Other Assets		
Nuclear decommissioning trust funds	**1,308.7**	1,240.1
Other investments	**524.2**	308.6
Regulatory assets (net)	**606.0**	389.0
Goodwill	**273.8**	157.6
Mark-to-market energy assets	**699.9**	623.4
Risk management assets	**449.2**	325.7
Unamortized energy contract assets	**186.2**	123.6
Other	**316.4**	311.4
Total investments and other assets	**4,364.4**	3,479.4
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**7,936.9**	7,587.6
Regulated property, plant and equipment	**5,968.4**	5,752.9
Nuclear fuel (net of amortization)	**382.1**	339.9
Accumulated depreciation	**(4,729.9)**	(4,458.3)
Net property, plant and equipment	**9,557.5**	9,222.1
Total Assets	**$ 21,752.3**	$ 21,801.6

** Unaudited*

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	September 30, 2007*	December 31, 2006
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	$ **295.5**	$ 878.8
Accounts payable and accrued liabilities	**2,301.5**	2,137.2
Customer deposits and collateral	**402.3**	347.2
Mark-to-market energy liabilities	**687.1**	1,071.7
Risk management liabilities	**840.8**	1,340.0
Unamortized energy contract liabilities	**415.7**	378.3
Accrued expenses and other	**868.3**	969.5
Total current liabilities	**5,811.2**	7,122.7
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,310.7**	1,435.8
Asset retirement obligations	**903.1**	974.8
Mark-to-market energy liabilities	**406.8**	392.4
Risk management liabilities	**802.3**	707.3
Unamortized energy contract liabilities	**1,279.8**	958.0
Defined benefit obligations	**849.5**	928.3
Deferred investment tax credits	**52.1**	57.2
Other	**167.8**	109.0
Total deferred credits and other liabilities	**5,772.1**	5,562.8
Long-term Debt		
Long-term debt of Constellation Energy	**2,453.8**	3,042.9
Long-term debt of nonregulated businesses	**324.2**	347.4
Rate stabilization bonds of BGE	**623.2**	
First refunding mortgage bonds of BGE	**119.7**	244.5
Other long-term debt of BGE	**1,214.5**	1,214.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(5.1)**	(5.9)
Current portion of long-term debt	**(295.5)**	(878.8)
Total long-term debt	**4,692.5**	4,222.3
Minority Interests	**19.9**	94.5
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock	**2,749.7**	2,738.6
Retained earnings	**3,763.4**	3,474.3
Accumulated other comprehensive loss	**(1,246.5)**	(1,603.6)

		September 30, 2007*		December 31, 2006
Total common shareholders' equity		**5,266.6**		4,609.3
Commitments, Guarantees, and Contingencies (see Notes)				
Total Liabilities and Equity	**$**	**21,752.3**	$	21,801.6

** Unaudited*

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Nine Months Ended September 30,	2007	2006
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 563.4**	$ 531.5
Adjustments to reconcile to net cash provided by operating activities		
Gain on sales of discontinued operations		(0.9)
Depreciation, depletion, and amortization	**309.7**	419.5
Accretion of asset retirement obligations	**51.9**	50.2
Deferred income taxes	**118.7**	73.8
Investment tax credit adjustments	**(5.0)**	(5.2)
Deferred fuel costs	**(248.7)**	(164.7)
Defined benefit obligation expense	**105.7**	111.4
Defined benefit obligation payments	**(153.7)**	(78.3)
Workforce reduction costs	**2.3**	23.9
Impairment losses and other costs	**20.2**	
Gains on sale of CEP LLC equity	**(52.1)**	
Equity in earnings of affiliates less than dividends received	**36.6**	12.9
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149	**15.1**	(38.9)
Changes in		
Accounts receivable	**(142.1)**	(367.7)
Mark-to-market energy assets and liabilities	**(55.7)**	(241.5)
Risk management assets and liabilities	**(23.2)**	(3.1)
Materials, supplies, and fuel stocks	**10.9**	(267.9)
Other current assets	**19.9**	53.9
Accounts payable and accrued liabilities	**100.4**	30.9
Other current liabilities	**(52.2)**	32.9
Other	**(5.4)**	(9.6)
Net cash provided by operating activities	**616.7**	163.1
Cash Flows From Investing Activities		
Investments in property, plant and equipment	**(920.3)**	(668.0)
Acquisitions, net of cash acquired	**(344.1)**	(133.5)
Investments in nuclear decommissioning trust fund securities	**(514.6)**	(348.4)
Proceeds from nuclear decommissioning trust fund securities	**505.8**	339.6
Sales of investments and other assets	**5.6**	43.5
Contract and portfolio acquisitions	**(474.2)**	(2.3)
Issuances of loans receivable	**(19.0)**	(65.4)
Other	**(65.4)**	33.8
Net cash used in investing activities	**(1,826.2)**	(800.7)
Cash Flows From Financing Activities		
Net issuance of short-term borrowings		184.3
Proceeds from issuance of		
Common stock	**47.7**	56.2
Long-term debt	**647.2**	122.0
Repayment of long-term debt	**(740.2)**	(285.8)
Common stock dividends paid	**(226.8)**	(195.7)
Reacquisition of common stock	**(114.4)**	
Proceeds from contract and portfolio acquisitions	**847.8**	221.3
	(15.1)	38.9

Nine Months Ended September 30,	2007	2006
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149		
Other	**25.9**	4.1
Net cash provided by financing activities	**472.1**	145.3
Net Decrease in Cash and Cash Equivalents	**(737.4)**	(492.3)
Cash and Cash Equivalents at Beginning of Period	**2,289.1**	813.0
Cash and Cash Equivalents at End of Period	**$ 1,551.7**	$ 320.7

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

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

	Three Months Ended September 30,		*Nine Months Ended September 30,*	
	2007	**2006**	**2007**	**2006**
		(In millions)		
Revenues				
Electric revenues	**$ 778.2**	$ 649.9	**$ 1,837.3**	$ 1,652.6
Gas revenues	**118.7**	114.6	**688.8**	678.4
Total revenues	**896.9**	764.5	**2,526.1**	2,331.0
Expenses				
Operating expenses				
Electricity purchased for resale	**522.6**	391.1	**1,117.7**	933.8
Gas purchased for resale	**70.6**	66.4	**457.6**	448.6
Operations and maintenance	**134.8**	123.9	**389.2**	364.2
Merger-related costs		0.8		3.3
Depreciation and amortization	**58.4**	57.2	**175.8**	172.1
Taxes other than income taxes	**44.0**	42.1	**132.8**	126.4
Total expenses	**830.4**	681.5	**2,273.1**	2,048.4
Income from Operations	**66.5**	83.0	**253.0**	282.6
Other Income	**9.2**	3.9	**19.2**	4.9
Fixed Charges				
Interest expense	**35.3**	24.8	**92.4**	73.3
Allowance for borrowed funds used during construction	**(0.7)**	(0.5)	**(1.8)**	(1.4)
Total fixed charges	**34.6**	24.3	**90.6**	71.9
Income Before Income Taxes	**41.1**	62.6	**181.6**	215.6
Income Taxes	**13.4**	23.7	**67.7**	83.3
Net Income	**27.7**	38.9	**113.9**	132.3
Preference Stock Dividends	**3.3**	3.3	**9.9**	9.9
Earnings Applicable to Common Stock	**$ 24.4**	$ 35.6	**$ 104.0**	$ 122.4

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	September 30, **2007***	*December 31,* **2006**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 18.4**	$ 10.9
Accounts receivable (net of allowance for uncollectibles of **$16.7** and $15.5, respectively)	**328.2**	190.3
Accounts receivable, unbilled	**142.2**	154.4
Investment in cash pool, affiliated company	**261.8**	60.6
Accounts receivable, affiliated companies	**3.2**	2.5
Fuel stocks	**113.6**	110.9
Materials and supplies	**44.0**	40.2
Prepaid taxes other than income taxes	**31.5**	48.0
Regulatory assets, net	**65.6**	62.5
Other	**22.6**	35.2
Total current assets	**1,031.1**	715.5
Investments and Other Assets		
Regulatory assets (net)	**606.0**	389.0
Receivable, affiliated company	**157.6**	150.5
Other	**149.0**	127.5
Total investments and other assets	**912.6**	667.0
Utility Plant		
Plant in service		
Electric	**4,183.8**	4,060.2
Gas	**1,173.9**	1,148.3
Common	**465.2**	444.6
Total plant in service	**5,822.9**	5,653.1
Accumulated depreciation	**(2,069.9)**	(1,994.7)
Net plant in service	**3,753.0**	3,658.4
Construction work in progress	**143.1**	97.1
Plant held for future use	**2.4**	2.7
Net utility plant	**3,898.5**	3,758.2
Total Assets	**$ 5,842.2**	$ 5,140.7

** Unaudited*

See Notes to Consolidated Financial Statements.

Certain prior-period amounts have been reclassified to conform with the current period's presentation.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	September 30, 2007 *	***December 31, 2006***
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 284.5**	$ 258.3
Accounts payable and accrued liabilities	**138.1**	187.3
Accounts payable and accrued liabilities, affiliated companies	**223.9**	163.4
Customer deposits	**70.9**	71.4
Deferred income taxes	**39.7**	47.4
Accrued expenses and other	**165.3**	98.3
Total current liabilities	**922.4**	826.1
Deferred Credits and Other Liabilities		
Deferred income taxes	**772.8**	697.7
Payable, affiliated company	**251.0**	250.7
Deferred investment tax credits	**12.3**	13.5
Other	**21.9**	14.0
Total deferred credits and other liabilities	**1,058.0**	975.9
Long-term Debt		
Rate stabilization bonds	**623.2**	
First refunding mortgage bonds	**119.7**	244.5
Other long-term debt	**1,214.5**	1,214.5
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
Long-term debt of nonregulated businesses	**25.0**	25.0
Unamortized discount and premium	**(2.7)**	(2.9)
Current portion of long-term debt	**(284.5)**	(258.3)
Total long-term debt	**1,952.9**	1,480.5
Minority Interest	**16.7**	16.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**789.3**	738.6
Accumulated other comprehensive income	**0.7**	0.7
Total common shareholder's equity	**1,702.2**	1,651.5

Commitments, Guarantees, and Contingencies (see Notes)

		September 30, **2007 ***		*December 31,* **2006**
Total Liabilities and Equity	**$**	**5,842.2**	$	5,140.7

** Unaudited*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Nine Months Ended September 30,	2007	2006
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 113.9**	$ 132.3
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**185.3**	182.5
Deferred income taxes	**85.5**	59.0
Investment tax credit adjustments	**(1.2)**	(1.2)
Deferred fuel costs	**(248.7)**	(164.7)
Defined benefit plan expenses	**31.7**	33.4
Merger-related costs		3.3
Allowance for equity funds used during construction	**(3.4)**	(2.6)
Changes in		
Accounts receivable	**(125.7)**	169.8
Accounts receivable, affiliated companies	**(0.7)**	(29.1)
Materials, supplies, and fuel stocks	**(6.5)**	(14.4)
Other current assets	**47.0**	(11.7)
Accounts payable and accrued liabilities	**(49.2)**	(8.3)
Accounts payable and accrued liabilities, affiliated companies	**7.5**	(18.7)
Other current liabilities	**31.3**	(3.7)
Long-term receivables and payables, affiliated companies	**(38.5)**	(38.3)
Other	**(22.4)**	(12.0)
Net cash provided by operating activities	**5.9**	275.6
Cash Flows From Investing Activities		
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(264.6)**	(225.2)
Change in cash pool at parent	**(201.2)**	144.1
Other	**(21.1)**	10.3
Net cash used in investing activities	**(486.9)**	(70.8)
Cash Flows From Financing Activities		
Proceeds from issuance of long-term debt	**623.2**	
Repayment of long-term debt	**(124.8)**	(135.3)
Preference stock dividends paid	**(9.9)**	(9.9)
Distribution to parent		(59.8)
Net cash provided by (used in) financing activities	**488.5**	(205.0)
Net Increase (Decrease) in Cash and Cash Equivalents	**7.5**	(0.2)
Cash and Cash Equivalents at Beginning of Period	**10.9**	15.1
Cash and Cash Equivalents at End of Period	**$ 18.4**	$ 14.9

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

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.

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.

Variable Interest Entities

We have a significant interest in the following variable interest entities (VIE) for which we are not the primary beneficiary:

VIE	Nature of Involvement	Date of Involvement
Power projects	Equity investment and guarantees	Prior to 2003
Power contract monetization entities	Power sale agreements, loans, and guarantees	March 2005
Oil and gas fields	Equity investment	May 2006
Retail power supply	Power sale agreement	September 2006

We discuss the nature of our involvement with the power contract monetization VIEs in detail in *Note 4* to our 2006 Annual Report on Form 10-K.

The following is summary information available as of September 30, 2007 about the VIEs in which we have a significant interest, but are not the primary beneficiary:

	Power Contract Monetization VIEs	All Other VIEs	Total
		(In millions)	
Total assets	$ 739.6	$ 399.1	$ 1,138.7
Total liabilities	586.2	199.4	785.6
Our ownership interest		53.4	53.4
Other ownership interests	153.4	146.3	299.7
Our maximum exposure to loss	59.5	165.6	225.1

The maximum exposure to loss represents the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of September 30, 2007 consists of the following:

- outstanding receivables, loans and letters of credit totaling $159.4 million,
- the carrying amount of our investment totaling $53.0 million, and
- debt and performance guarantees totaling $12.7 million.

We assess the risk of a loss equal to our maximum exposure to be remote.

RSB BondCo LLC

In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy-remote limited liability company. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. We discuss Senate Bill 1 in more detail in our 2006 Annual Report on Form 10-K.

BGE has determined that BondCo is a variable interest entity for which it is also the primary beneficiary. As a result, BGE consolidated BondCo. We discuss the consolidation method of accounting in more detail in *Note 1* of our 2006 Annual Report on Form 10-K and the issuance of rate stabilization bonds by BondCo on page 17 of *Notes to Consolidated Financial Statements*.

Discontinued Operations

In the fourth quarter of 2006, we completed the sale of six natural gas-fired plants, including the High Desert facility, which was classified as discontinued operations. We recognized an after-tax loss of $1.6 million as a component of "Income (loss) from discontinued operations" in the first quarter of 2007 due to post-closing working capital adjustments. We discuss the details of the sale in *Note 2* of our 2006 Annual Report on Form 10-K. In the third quarter of 2007, we recognized an after-tax gain of $0.7 million relating to income tax adjustments arising from the sale of the High Desert facility and the June 2004 sale of a geothermal generating facility in Hawaii that was also previously classified as discontinued operations.

Impairment Losses and Other Costs

In October 2006, in connection with the termination of the merger agreement with FPL Group, Inc., we acquired certain rights relating to a wind development project in Western Maryland. In the second quarter of 2007, we elected not to make the additional investment that was required at that time to retain our rights in the project; therefore, we recorded a charge of $20.2 million pre-tax to write-off our investment in these development rights.

Workforce Reduction Costs

We incurred costs related to workforce reduction efforts initiated in 2006. We discuss these costs in more detail in *Note 2* of our 2006 Annual Report on Form 10-K.

The following table summarizes the status of the 2006 involuntary severance liability for Nine Mile Point and Calvert Cliffs at September 30, 2007:

		(In millions)
Initial severance liability balance	$	19.6
Amounts recorded as pension and postretirement liabilities		(7.3)
Net cash severance liability		12.3
Cash severance payments		(10.3)
Other		
Severance liability balance at September 30, 2007	$	2.0

In June 2007, we approved an additional restructuring of the workforce at our Nine Mile Point nuclear facility. The following table summarizes the status of this involuntary severance liability for Nine Mile Point at September 30, 2007:

		(In millions)
Initial severance liability balance[1]	$	2.6
Amounts recorded as pension and postretirement liabilities		(1.5)
Net cash severance liability		1.1
Cash severance payments		
Other		
Severance liability balance at September 30, 2007	$	1.1

1 Includes $0.3 million to be reimbursed from co-owner.

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing earnings applicable 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 September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Non-dilutive stock options		2.0		2.0
Dilutive common stock equivalent shares	**2.3**	1.9	**2.3**	1.8

Accretion of Asset Retirement Obligations

We discuss our asset retirement obligations in more detail in *Note 1* of our 2006 Annual Report on Form 10-K. The change in our "Asset retirement obligations" liability during 2007 was as follows:

		(In millions)
Liability at January 1, 2007	$	974.8
Accretion expense		51.9
Liabilities incurred		3.4
Liabilities settled		(0.3)
Revisions to expected future cash flows		(123.8)
Other		(2.9)
Liability at September 30, 2007	$	903.1

Substantially all of the $123.8 million "Revisions to expected future cash flows" represents the decrease to our nuclear decommissioning asset retirement obligations in conjunction with site-specific studies that we completed in the third quarter of 2007 for all three of our nuclear sites. We perform site-specific studies from time to time to update our asset retirement obligations. These studies reassessed the key assumptions involved in estimating the expected future cost of nuclear decommissioning activities. The resulting decrease in the expected future cost of nuclear decommissioning and the related asset retirement obligation is primarily due to a fleet-based approach incorporating recent industry experiences, technological advances, improved economies of scale, and the certainty of Nine Mile Point's license renewal, which was approved in late 2006.

"Other" represents Constellation Energy Partners LLC's (CEP) asset retirement obligation that is no longer included in our Consolidated Balance Sheets. We discuss the deconsolidation of CEP below.

Constellation Energy Partners LLC

In April 2007, CEP acquired 100% ownership of certain coalbed methane properties located in the Cherokee Basin in Kansas and Oklahoma. This acquisition was funded through CEP's issuance of equity. In anticipation of closing this acquisition and the related equity issuance, at March 31, 2007 we evaluated the probability of forecasted sales of natural gas from CEP's properties that previously had been hedged by our merchant energy business. As a result of the anticipated deconsolidation of CEP resulting from this equity issuance, which we discuss below, we determined that the hedged forecasted sales were probable of not occurring. Therefore, we reclassified $21.8 million pre-tax in previously deferred cash-flow hedge losses from "Accumulated other comprehensive loss" to earnings during the first quarter of 2007.

As a result of the April 2007 equity issuance by CEP, our ownership percentage in CEP fell below 50 percent. Therefore, during the second quarter of 2007, we deconsolidated CEP and began accounting for our investment using the equity method under Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock.* We discuss the equity method of accounting in more detail in *Note 1* of our 2006 Annual Report on Form 10-K.

In July and September 2007, CEP issued additional equity. In connection with our equity ownership in CEP, we recognize gains on CEP's equity issuances in the period that the equity is sold as common units or when converted to common units. The details of the 2007 CEP equity issuances as well as the gains recognized by us, are summarized below:

	Units Issued	Price/ Unit	Proceeds to CEP	Pre-tax Gain
	(In millions, except price/unit)			
April 2007 Sale				
Common units	2.2	$ 26.12	$ 58	$ 12.5
Class E units[1]	0.1	25.84	2	0.4
July 2007 Sale				
Common units	2.7	35.25	94	20.0
Class F units[2]	3.4	34.43	116	12.8
September 2007 Sale				
Common units	2.5	42.50	105	19.2

1 The gain on Class E units was recognized upon conversion to common units in the quarter ended June 30, 2007.

2 The gain on Class F units was recognized upon conversion to common units in October 2007.

Acquisitions

Working Interests in Gas Producing Fields

In the first quarter of 2007, we acquired working interests of 41% and 55% in two gas and oil producing properties in Oklahoma for $208.9 million, subject to closing adjustments. We purchased leases, producing wells, inventory, and related equipment. We have included the results of operations from these properties in our merchant energy business segment since the date of acquisition.

Our purchase price was allocated to the net assets acquired as follows:

At March 23, 2007

		(In millions)
Property, Plant and Equipment		
Inventory	$	0.2
Unproved property		28.8
Proved property		179.9
Net Assets Acquired	$	208.9

The pro-forma impact of the acquisition of these working interests would not have been material to our results of operations for the three months ended March 31, 2007 and for the three and nine month periods ended September 30, 2006.

Contract and Portfolio Acquisitions

In June 2007, our wholesale marketing, risk management, and trading operation closed a transaction for the purchase of a portfolio of power-related contracts in the southeast region of the United States. Under this transaction, we assumed several full-requirements fixed-price power sales agreements with peak demand totaling more than 3,000 megawatts, and several long-term tolling agreements. The power sales and tolling agreements terminate at various dates through 2015. In addition, we also assumed various power and natural gas hedges.

The market price was different than the contract prices at closing. As a result, each contract was evaluated to determine whether the fair value of the contract price was above- or below-market at the time of closing. We recorded the fair value of each contract as an asset if the fair value was above-market (in-the-money) and as a liability if the contract was below-market (out-of-the-money).

The table below summarizes the transaction and the net cash received at closing:

		(In millions)
Contracts out-of-the-money at closing	$	820.8
Contracts in-the-money at closing		(474.2)
Net cash received at closing	$	346.6

We recorded this transaction in our financial statements as follows:

	Balance Sheet	**Cash Flows**
Acquisition of out- of-the-money contracts	Unamortized energy contract liabilities and risk management liabilities	Financing cash inflow
Acquisition of in- the-money contracts	Unamortized energy contract assets, mark-to-market energy assets, risk management assets, and accounts receivable	Investing cash outflow

We recorded the cash received at the acquisition of contracts that are out-of-the-money at closing as a financing cash inflow because it does not represent a cash inflow from current period operating activities. For those acquired contracts that are derivatives, we record the ongoing cash flows related to the contract with the counterparties as financing cash flows in accordance with SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities.* We record all other ongoing cash flows from the sale or purchase of power under contracts assumed in this transaction as operating cash flows.

Cornerstone Energy

On July 1, 2007, we acquired Cornerstone Energy, Inc (CEI). We include CEI, part of our retail competitive supply operation, in our merchant energy business and have included its results of operations in our consolidated financial statements since the date of acquisition. CEI provides natural gas supply and related services to commercial, industrial and institutional customers across the central United States. CEI is expected to add approximately 100 billion cubic feet of natural gas to our annual volumes served.

We acquired 100% ownership for $100.8 million, which was paid in cash at closing. As part of the purchase, we acquired $7.3 million in cash.

The total consideration for accounting purposes, consisting of cash and other noncash consideration, including the fair value of certain preexisting contracts with CEI, was equal to $145.2 million and was allocated to the net assets acquired as follows:

At July 1, 2007

		(In millions)
Cash	$	7.3
Other Current Assets		84.9
Total Current Assets		92.2
Goodwill[(1)]		115.9
Net Property, Plant and Equipment		0.5
Other Assets		6.7
Total Assets Acquired		215.3

At July 1, 2007

Current Liabilities		(66.5)
Deferred Credits and Other Liabilities		(3.6)
Total Liabilities		(70.1)
Net Assets Acquired	$	145.2

1 Deductible for tax purposes.

Our purchase price allocation is based on preliminary estimates, and the purchase price is subject to adjustments, both of which could impact our purchase price allocation.

The pro-forma impact of the CEI acquisition would not have been material to our results of operations for the three and six months ended June 30, 2007 and for the three and nine months ended September 30, 2006.

Shipping Joint Venture

In December 2006, we formed a shipping joint venture in which we have a 50% ownership interest. The joint venture will own and operate six freight ships. In the third quarter of 2007, we made cash contributions of approximately $44 million to the joint venture. We expect our total cash contribution will be approximately $60 million in 2007. The joint venture is accounted for using the equity method of accounting under APB No. 18. We discuss the equity method of accounting in more detail in *Note 1* of our 2006 Annual Report on Form 10-K.

Electricite de France Joint Venture

In August 2007, we formed a joint venture, UniStar Nuclear Energy, LLC (UniStar) with an affiliate of Electricite de France, SA (EDF). We have a 50% ownership interest in this joint venture to develop, own, and operate new nuclear projects in the United States and Canada. This joint venture will be accounted for using the equity method of accounting under APB No. 18. The agreement with EDF includes a phased-in investment of $625 million by EDF in UniStar. Initially, EDF invested $350 million in UniStar during the quarter ended September 30, 2007, and we contributed the new nuclear line of businesses we have developed over the past two years, which included assets with a book value of $47 million and the right to develop possible new nuclear projects at our existing nuclear plant locations. Upon reaching certain licensing milestones, EDF will contribute up to an additional $275 million in UniStar.

In connection with this joint venture, we entered into an investor agreement with EDF under which EDF may purchase in the open market up to a total of 9.9% of our outstanding common stock during the next five years, with a limit of 5% ownership during the first twelve months of the agreement. EDF has agreed to vote any shares of our common stock owned by it in the manner recommended by our board of directors and not to take any actions that seek control of Constellation Energy during the next five years.

Common Share Repurchase Program

In October 2007, our board of directors approved a common share repurchase program for up to $1 billion of our outstanding common shares. Subsequent to this approval, on October 31, 2007, we entered into an accelerated share repurchase agreement with a financial institution, and, on November 2, 2007, we purchased 2,023,527 of outstanding shares of our common stock, which represents the minimum number of shares deliverable under the agreement, for a total of $250 million. The $250 million payment was funded from available cash on hand. The final price of the shares repurchased will be determined based on a discount to the volume-weighted average trading price of our common stock during a period of up to three months. Depending on the final price of the repurchased shares, the financial institution may deliver additional shares to us at the completion of the transaction. The shares repurchased in November 2007 will be accounted for as a reduction to common shareholders' equity at cost in the fourth quarter of 2007. The remainder of the program is expected to be executed over the next 24 months in a manner that preserves flexibility to pursue additional strategic investment opportunities.

Information by Operating Segment

Our reportable operating segments are Merchant Energy, Regulated Electric, and Regulated Gas:

- Our merchant energy business is nonregulated and includes:
  - full requirements load-serving sales of energy and capacity to utilities, cooperatives, and commercial, industrial, and governmental customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs),
  - deployment of risk capital through portfolio management and trading activities,
  - gas retail energy products and services to commercial, industrial, and governmental customers,
  - fossil, nuclear, and interests in hydroelectric generating facilities and qualifying facilities, fuel processing facilities, and power projects in the United States,
  - upstream (exploration and production) and downstream (transportation and storage) natural gas operations,
  - coal sourcing and logistics services for the variable or fixed supply needs of global customers, and
  - generation operations and maintenance and new nuclear development, including consulting services.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Central Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Central Maryland.

Our remaining nonregulated businesses:

- design, construct, and operate heating, cooling, and cogeneration facilities for commercial, industrial, and municipal customers throughout North America, and
- provide home improvements, service electric and gas appliances, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide natural gas marketing to residential customers in Central Maryland.

In addition, we own several investments that we do not consider to be core operations. These include financial investments and real estate projects.

Our Merchant Energy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology 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 on the next page.

	Reportable Segments					
	Merchant Energy Business	**Regulated Electric Business**	**Regulated Gas Business**	**Other Nonregulated Businesses**	**Eliminations**	**Consolidated**
				(In millions)		
For the three months ended September 30,						
2007						
Unaffiliated revenues	**$ 4,910.4**	**$ 778.2**	**$ 112.8**	**$ 55.0**	**$**	**$ 5,856.4**
Intersegment revenues	**365.5**		**5.9**		**(371.4)**	
Total revenues	**5,275.9**	**778.2**	**118.7**	**55.0**	**(371.4)**	**5,856.4**
Income from discontinued operations	**0.7**					**0.7**
Net income (loss)	**227.2**	**34.3**	**(9.8)**	**(0.3)**		**251.4**
2006						
Unaffiliated revenues	$ 4,586.3	$ 649.9	$ 111.7	$ 45.5	$	$ 5,393.4
Intersegment revenues	422.4		2.9		(425.3)	
Total revenues	5,008.7	649.9	114.6	45.5	(425.3)	5,393.4
Income from discontinued operations	18.1					18.1
Net income (loss)	284.8	42.8	(7.3)	4.1		324.4
For the nine months ended September 30,						
2007						
Unaffiliated revenues	**$ 13,157.6**	**$ 1,837.3**	**$ 674.4**	**$ 174.5**	**$**	**$ 15,843.8**
Intersegment revenues	**956.1**		**14.4**		**(970.5)**	
Total revenues	**14,113.7**	**1,837.3**	**688.8**	**174.5**	**(970.5)**	**15,843.8**
Loss from discontinued operations	**(0.9)**					**(0.9)**
Net income	**449.4**	**85.9**	**18.2**	**9.9**		**563.4**
2006						
Unaffiliated revenues	$ 12,137.8	$ 1,652.6	$ 671.8	$ 169.2	$	$ 14,631.4
Intersegment revenues	862.1		6.6	0.1	(868.8)	
Total revenues	12,999.9	1,652.6	678.4	169.3	(868.8)	14,631.4
Income from discontinued operations	48.6			0.9		49.5
Net income	400.1	96.3	26.3	8.8		531.5

Certain prior period amounts have been reclassified to conform with the current period's presentation. Revenues for the nine months ended September 30, 2007 reflect the reclassification of $111.7 million relating to the six months ended June 30, 2007 to conform with the current period presentation. Prior year reclassifications relate to operations that have been classified as discontinued operations.

Pension and Postretirement Benefits

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Components of net periodic pension benefit cost				
Service cost	**$ 13.3**	$ 11.9	**$ 38.0**	$ 36.5
Interest cost	**25.6**	22.0	**72.9**	66.5
Expected return on plan assets	**(27.8)**	(23.6)	**(79.1)**	(72.1)
Recognized net actuarial loss	**8.7**	9.2	**25.1**	28.0
Amortization of prior service cost	**1.4**	1.4	**4.0**	4.2
Amount capitalized as construction cost	**(2.9)**	(3.1)	**(8.8)**	(9.8)
Net periodic pension benefit cost[1]	**$ 18.3**	$ 17.8	**$ 52.1**	$ 53.3

1 The amounts shown above do not reflect a settlement charge of $7.6 million recorded in the third quarter of 2006 related to one of our qualified pension plans. BGE's portion of our net periodic pension benefit cost, net of amounts capitalized, was $5.8 million for the quarter ended September 30, 2007 and $6.2 million for the quarter ended September 30, 2006. BGE's portion of our net periodic pension benefit cost, net of amounts capitalized, was $16.1 million for the nine months ended September 30, 2007 and $18.6 million for the nine months ended September 30, 2006.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Components of net periodic postretirement benefit cost				
Service cost	**$ 1.6**	$ 1.9	**$ 5.1**	$ 6.1
Interest cost	**5.7**	6.0	**19.0**	18.8
Amortization of transition obligation	**0.4**	0.6	**1.6**	1.7
Recognized net actuarial loss	**1.0**	1.6	**3.2**	5.2
Amortization of prior service cost	**(0.8)**	(0.9)	**(2.7)**	(2.8)
Amount capitalized as construction cost	**(1.7)**	(2.0)	**(6.0)**	(6.3)
Net periodic postretirement benefit cost[1]	**$ 6.2**	$ 7.2	**$ 20.2**	$ 22.7

1 BGE's portion of our net periodic postretirement benefit cost, net of amounts capitalized, was $3.7 million for the quarter ended September 30, 2007 and $4.2 million for the quarter ended September 30, 2006. BGE's portion of our net periodic postretirement benefit costs, net of amounts capitalized, was $11.9 million for the nine months ended September 30, 2007 and $12.9 million for the nine months ended September 30, 2006.

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 $5 million in pension benefit payments for our non-qualified pension plans and approximately $29 million for retiree health and life insurance benefit payments during 2007. We contributed $125.0 million to our qualified pension plans in March 2007.

Financing Activities

In July 2007, we entered into a new five-year credit facility totaling $3.85 billion. This new facility amended and restated three facilities totaling $3.35 billion a $1.5 billion facility that would have expired in March 2010, a $1.1 billion facility that would have expired in November 2010, and a $750 million facility that would have expired in November 2010. In connection with entering into the new five-year credit facility, we terminated a $1.0 billion facility that would have expired in October 2007. As of November 1, 2007, we had committed bank lines of credit under facilities totaling $4.05 billion for short-term financial needs. These facilities can issue letters of credit up to approximately $4.05 billion. Letters of credit issued under all of our facilities totaled $1.9 billion at September 30, 2007.

In June 2007, BondCo, a subsidiary of BGE, issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover deferred power purchase costs. We discuss BondCo in more detail on page 11. Below are the details of the rate stabilization bonds:

Principal	Interest Rate	Scheduled Maturity Date
$284.0	5.47%	October 2012
220.0	5.72	April 2016
119.2	5.82	April 2017

The bonds are secured primarily by a usage-based, non-bypassable charge payable by all of BGE's residential electric customers over the next ten years. The charges will be adjusted semi-annually to ensure that the aggregate charges collected are sufficient to pay principal and interest on the bonds as well as certain on-going costs of administering and servicing the bonds. BondCo cannot use the charges collected to satisfy any other obligations. BondCo's assets are not assets of any affiliate and are not available to pay creditors of any affiliate of BondCo. If BondCo is unable to make principal and interest payments on the bonds, neither Constellation Energy nor BGE are required to make the payments on behalf of BondCo.

In connection with the equity issuance by CEP in April 2007, which is discussed on page 13, we deconsolidated CEP and began accounting for our investment using the equity method of accounting under APB No. 18. As a result, the $32.0 million of borrowings outstanding under the CEP credit facility at the time of deconsolidation are no longer included in our Consolidated Balance Sheets.

Under our shareholder investment plans we issued $47.7 million of common stock during the nine months ended September 30, 2007. In addition, during the first nine months of 2007, we purchased $114.4 million of our common stock in the open market. These common shares are held by us in order to satisfy employee stock-based compensation obligations.

Income Taxes

Total income taxes are different from the amount that would be computed by applying the statutory Federal income tax rate of 35% to book income before income taxes as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Income before income taxes (excluding BGE preference stock dividends)	**$ 418.3**	$ 460.8	**$ 832.6**	$ 722.5
Statutory federal income tax rate	**35%**	35%	**35%**	35%
Income taxes computed at statutory federal rate	**146.4**	161.4	**291.4**	252.9
(Decreases) increases in income taxes due to:				
Synthetic fuel tax credits flowed through to income	**(37.1)**	(15.2)	**(119.7)**	(87.4)
Synthetic fuel tax credit phase-out	**20.1**	6.4	**44.0**	48.0
Phase-out true up from prior periods	**20.5**	(19.0)	**12.6**	(15.3)
State income taxes, net of federal tax benefit	**19.0**	18.7	**36.6**	32.3
Other	**(4.6)**	(1.1)	**(6.5)**	0.1
Total income taxes	**$ 164.3**	$ 151.2	**$ 258.4**	$ 230.6
Effective tax rate	**39.3%**	32.8%	**31.0%**	31.9%

Certain prior year amounts have been reclassified to conform with the current year's presentation. The reclassifications relate to operations that have been classified as discontinued operations.

Synthetic fuel tax credits recognized through September 30, 2007 are net of our expectation of a 54% phase-out in 2007 based on forward market prices and volatilities at September 30, 2007. Based on forward market prices and volatilities as of October 26, 2007, we currently estimate a 69% tax credit phase-out in 2007. The expected amount of synthetic fuel tax credits phased-out may change materially from period to period as a result of continued changes in oil prices.

We discuss the adoption of the Financial Accounting Standards Board's (FASB) Interpretation No. (FIN) 48, *Accounting for Uncertainty in Income Taxes*, on page 24.

Taxes Other Than Income Taxes

BGE collects from certain customers franchise and other taxes 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. The taxes imposed on the customer are accounted for on a net basis, which means we do not recognize revenue and an offsetting tax expense for the taxes collected from customers. The taxes imposed on BGE are accounted for on a gross basis, which means we recognize revenue for the taxes collected from customers. Accordingly, the taxes accounted for on a gross basis are recorded as revenues in the accompanying Consolidated Statements of Income for BGE as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Taxes other than income taxes included in revenues BGE	**$ 19.4**	$ 18.5	**$ 57.9**	$ 55.7

Commitments, Guarantees, and Contingencies

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

- purchase of electric generating capacity and energy,
- procurement and delivery of fuels,
- the capacity and transmission and transportation rights for the physical delivery of energy to meet our obligations to our customers, and
- long-term service agreements, capital for construction programs, and other.

Our merchant energy business enters into various long-term contracts for the procurement and delivery of fuels to supply 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 2007 and 2020. In addition, our merchant energy business enters into long-term contracts for the capacity and transmission rights for the delivery of energy to meet our physical obligations to our customers. These contracts expire in various years between 2007 and 2019.

Our merchant energy business also has committed to long-term service agreements and other purchase commitments for our plants.

Our regulated electric business enters into various long-term contracts for the procurement of electricity. These contracts expire between 2007 and 2009. Our regulated gas business has gas transportation and storage contracts that expire between 2007 and 2028. As discussed in *Note 1* of our 2006 Annual Report on Form 10-K, the costs under these contracts are fully recoverable by our regulated businesses.

Our other nonregulated businesses have committed to gas purchases, as well as to contribute additional capital for construction programs and joint ventures in which they have an interest.

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

At September 30, 2007, the total amount of commitments was $7,574.0 million. These commitments are primarily related to our merchant energy business.

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 2019 and provide for the sale of energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with power plants we own extend for terms into 2014 and provide for the sale of all or a portion of the actual output of certain of our power plants. All long-term contracts were executed at pricing that approximated market rates, including profit margin, at the time of execution.

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 based on the stated limit of our outstanding guarantees:

At September 30, 2007

		Stated Limit
		(In millions)
Competitive supply guarantees	$	12,737.3
Nuclear guarantees		786.1
BGE guarantees		263.3
Other non-regulated guarantees		106.1
Power project guarantees		39.2
Total guarantees	$	13,932.0

At September 30, 2007, Constellation Energy had a total of $13,932.0 million in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below.

Constellation Energy guaranteed $12,737.3 million on behalf of our subsidiaries for competitive supply activities. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. While the face amount of these guarantees is $12,737.3 million, our calculated fair value of obligations for commercial transactions covered by these guarantees was $3,133.1 million at September 30, 2007. The $3,133.1 million represents the total amount Constellation Energy could be required to fund based on market prices as of September 30, 2007, if the subsidiaries do not honor contractual commitments covered by these guarantees. For those guarantees related to our mark-to-market energy or risk management liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets.

Constellation Energy guaranteed $786.1 million primarily on behalf of our 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.

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

BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At September 30, 2007, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million.

Constellation Energy guaranteed $95.1 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.0 million was recorded in our Consolidated Balance Sheets at September 30, 2007.

Our other nonregulated business guaranteed $11.0 million primarily for performance bonds.

Our merchant energy business guaranteed $39.2 million for loans and other performance guarantees related to certain power projects in which we have an investment.

We believe it is unlikely that we would be required to perform or incur any losses associated with guarantees of our subsidiaries' obligations.

Contingencies

Revenue Sufficiency Guarantee Costs

During 2006, the Federal Energy Regulatory Commission (FERC) issued orders finding that the Midwest Independent System Operator (MISO) violated its tariff by incorrectly allocating revenue sufficiency guarantee (RSG) charges among market participants. As a result of FERC orders, MISO proposed a revised methodology for the allocation of RSG charges in its December 2006 compliance filing with the FERC with a proposed effective date of April 1, 2007.

In March 2007, FERC rejected the RSG allocation methodology proposed by MISO in its December 2006 compliance filing and ordered MISO to reallocate RSG costs based on its existing tariff back to the date of FERC's original order (April 2006). Based on this FERC order, we recorded an immaterial liability in our Consolidated Balance Sheets based on our estimate of the amount of re-allocated RSGs we believe is probable. Our liability is subject to change based upon MISO's calculation of the actual RSG adjustment. In addition, the order may be appealed, and we cannot predict the ultimate timing or outcome of any appeal.

Environmental Matters

Solid and Hazardous Waste

The Environmental Protection Agency (EPA) and several state agencies have notified us that we are considered a potentially responsible party with respect to the clean-up of certain environmentally contaminated sites. We cannot estimate the final clean-up costs for all of these sites, but the current estimated costs for, and current status of, each site is described in more detail below.

68th Street Dump

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 liable 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 fully indemnified by a wholly-owned subsidiary of Constellation Energy for costs related to this settlement, as well as any clean-up costs. The clean-up costs will not be known until the investigation is closer to completion. However, those costs could have a material effect on our financial results.

Spring Gardens

In December 1996, BGE signed a consent order with the Maryland Department of the Environment that requires it to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. The Spring Gardens site was once used to manufacture gas from coal and oil. Based on remedial action plans and cost modeling performed in late 2006, BGE estimates its probable clean-up costs will total $43 million. BGE has recorded these costs as a liability in its Consolidated Balance Sheets and has deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Based on the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE has recognized by approximately $3 million. Through September 30, 2007, BGE has spent approximately $40 million for remediation at this site.

BGE also has investigated other small sites where gas was manufactured in the past. We do not expect the clean-up costs of the remaining smaller sites to have a material effect on our financial results.

Air Quality

In late July 2005, we received two Notices of Violation (NOVs) from the Placer County Air Pollution Control District, Placer County California (District) alleging that the Rio Bravo Rocklin facility located in Lincoln, California had violated certain District air emission regulations. We have a combined 50% ownership interest in the partnership which owns the Rio Bravo Rocklin facility. The NOVs allege a total of 38 violations between January 2003 and March 2005 of either the facility's air permit or federal, state, and county air emission standards related to nitrogen oxide, carbon monoxide, and particulate emissions, as well as violations of certain monitoring and reporting requirements during that time period. The maximum civil penalties for the alleged violations range from $10,000 to $40,000 per violation. Management of the Rio Bravo Rocklin facility is currently discussing the allegations in the NOVs with District representatives. It is not possible to determine the actual liability, if any, of the partnership that owns the Rio Bravo Rocklin facility.

In May 2007, a subsidiary of Constellation Energy entered into a consent decree with the Maryland Department of the Environment to resolve alleged violations of air quality opacity standards at three fossil fuel plants in Maryland. The consent decree requires the subsidiary to pay a $100,000 penalty, provide $100,000 to a supplemental environmental project, and install technology to control emissions from those plants.

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 $4 million, which includes the $1 million penalty and our estimate of probable costs to remediate contamination, replace drinking water supplies, and monitor groundwater conditions. 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.

Litigation

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

City of Tacoma v. AEP, et al., The City of Tacoma, on June 7, 2004, in the U.S. District Court, Western District of Washington, filed a complaint against over 60 companies, including Constellation Energy Commodities Group, Inc. (CCG). The complaint alleges that the defendants engaged in manipulation of electricity markets resulting in prices for power in the western power markets that were substantially above what market prices would have been in the absence of the alleged unlawful contracts, combinations and conspiracy in violation of Section 1 of the Sherman Act. The complaint further alleges that the total amount of damages is unknown, but is estimated to exceed $175 million. On February 11, 2005, the Court granted the defendants' motion to dismiss the action based on the Court's lack of jurisdiction over the claims in question. The plaintiff appealed the dismissal of the action to the Ninth Circuit Court of Appeals, but subsequently agreed to a dismissal with prejudice, which the Ninth Circuit Court ordered on March 20, 2007.

Challenges to the Illinois Auction

In March 2007, the Illinois Attorney General filed a complaint at FERC against the wholesale suppliers, including our wholesale marketing, risk management and trading operation, that were successful bidders in the recent Illinois auction. The complaint alleged that the rates resulting from the auction were not "just and reasonable" and requested that FERC commence a proceeding to determine if the rates were just and reasonable and to investigate evidence of price manipulation. In July 2007, the Illinois legislature approved comprehensive legislation to address several energy issues in the state, including dismissal of all claims against wholesale suppliers by the Attorney General, both in the state of Illinois and before the FERC. This legislation has been signed into law by the Governor of Illinois, and the Attorney General's claims have been dismissed.

In addition, two class action complaints have been filed in Illinois state court against these wholesale suppliers alleging that they engaged in deceptive practices, including colluding in setting prices and actual price fixing. The complaints seek unspecified damages in an amount to be proven at trial. These complaints subsequently were moved to federal court.

We believe we have meritorious defenses to these claims challenging the Illinois auction and our conduct in the auction and intend to defend against them vigorously. However, we cannot predict the timing, or outcome, of these proceedings, or their possible effect on our 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.

In rulings applicable to all but three of the cases, involving claims related to approximately 47 children, the Circuit Court for Baltimore City dismissed all claims against BGE and Constellation Energy. 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 the remaining actions vigorously. However, we cannot predict the timing, or 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.

BGE and Constellation Energy, and numerous other parties are defendants in these cases.

Approximately 535 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 against us have been dismissed or resolved without any payment and a small minority have been resolved for amounts that were not material to our financial results. The remaining claims are currently pending in state courts in Maryland and Pennsylvania.

BGE and Constellation Energy do not know the specific facts necessary to estimate their potential liability for 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.

Until the relevant facts are determined, we are unable to estimate what our, or BGE's, liability might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, the potential effect on our, or BGE's, financial results could be material.

Insurance

We discuss our nuclear and non-nuclear insurance programs in *Note 12* of our 2006 Annual Report on Form 10-K.

SFAS No. 133 Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities. We discuss our market risk in more detail in our 2006 Annual Report on Form 10-K.

Commodity Prices

Our merchant energy business uses a variety of derivative and non-derivative instruments to manage the commodity price risk of our competitive supply activities and our electric generation facilities, including power sales, fuel and energy purchases, gas purchased for resale, emission credits, weather risk, freight, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers, and
- fixing the price for a portion of anticipated sales of natural gas to customers.

The portion of forecasted transactions hedged may vary based upon management's assessment of market, weather, operational, and other factors.

Our merchant energy business designated certain fixed-price forward contracts as cash-flow hedges of forecasted sales of energy and forecasted purchases of fuel and energy for the years 2007 through 2016 under Statement of Financial Accounting Standard (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* Our merchant energy business had net unrealized pre-tax losses on these cash-flow hedges recorded in "Accumulated other comprehensive loss" of $1,685.3 million at September 30, 2007 and $2,227.1 million at December 31, 2006.

We expect to reclassify $1,019.8 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 September 30, 2007. However, the actual amount reclassified into earnings could vary from the amounts recorded at September 30, 2007, due to future changes in market prices. Additionally, for cash-flow hedges settled by physical delivery of the underlying commodity, "Reclassification of net losses on hedging instruments from OCI to net income" represents the fair value of those derivatives, which is realized through gross settlement at the contract price.

During the nine months ended September 30, 2007, we de-designated contracts previously designated as cash-flow hedges for which the forecasted transactions originally hedged are probable of not occurring and as a result we recognized a pre-tax loss of $21.6 million. We discuss the transaction that accounts for substantially all of this amount in more detail in the *Constellation Energy Partners LLC* section on page 13.

During the nine months ended September 30, 2006, we de-designated contracts previously designated as cash-flow hedges and as a result we recognized a pre-tax loss of $10.5 million.

Our merchant energy business also enters into natural gas storage contracts under which the gas in storage qualifies for fair value hedge accounting treatment under SFAS No. 133.

We record changes in fair value of hedges related to our retail competitive supply operations as a component of "Fuel and purchased energy expenses" in our Consolidated Statements of Income. We record changes in fair value of hedges related to our wholesale competitive supply operations as a component of "Nonregulated revenues" in our Consolidated Statements of Income.

We recorded in earnings the following pre-tax gains (losses) related to hedge ineffectiveness:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
		(In millions)		
Cash-flow hedges	**$ 32.5**	$ (1.9)	**$ 2.2**	$ 3.7
Fair value hedges	**(1.6)**	6.3	**(0.5)**	7.9
Total	**$ 30.9**	$ 4.4	**$ 1.7**	$ 11.6

The ineffectiveness amounts in the table above exclude $9.1 million of pre-tax gains and $7.3 million of pre-tax losses that we recognized as a result of market price changes for the quarter and nine months ended September 30, 2007, respectively. These amounts represent the change in fair value of derivatives that did not qualify for cash-flow hedge accounting due to reduced price correlation between the hedge and the risk being hedged, but remain designated as hedges prospectively. Corresponding amounts for the prior year were immaterial.

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances, to manage our exposure to fluctuations in interest rates on variable rate debt, and to optimize the mix of fixed and floating-rate debt. The swaps used to manage our exposure prior to the issuance of new debt are designated as cash-flow hedges under SFAS No. 133, with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in "Accumulated other comprehensive loss" in anticipation of planned financing transactions. We reclassify gains and losses on the hedges from "Accumulated other comprehensive loss" into "Interest expense" in our Consolidated Statements of Income during the periods in which the interest payments being hedged occur.

The swaps used to optimize the mix of fixed and floating-rate debt are designated as fair value hedges under SFAS No. 133. We record any gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as changes in the fair value of the debt being hedged, in "Interest expense," and we record any changes in fair value of the swaps and the debt in "Risk management assets and liabilities" and "Long-term debt" in our Consolidated Balance Sheets. In addition, we record the difference between interest on hedged fixed-rate debt and floating-rate swaps in "Interest expense" in the periods that the swaps settle.

"Accumulated other comprehensive loss" includes net unrealized pre-tax gains on interest rate cash-flow hedges terminated upon debt issuance totaling $11.9 million at September 30, 2007 and $12.5 million at December 31, 2006. We expect to reclassify $0.1 million of pre-tax net losses 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.

In order to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps qualifying as fair value hedges relating to $450.0 million of our fixed-rate debt maturing in 2012 and 2015, and converted this notional amount of debt to floating-rate. The fair value of these hedges was an unrealized gain of $3.8 million at September 30, 2007 and was recorded as an increase in our "Risk management assets" and an increase in our "Long-term debt." The fair value of these hedges was an unrealized loss of $7.1 million at December 31, 2006 and was recorded as an increase in our "Risk management liabilities" and a decrease in our "Long-term debt." We had no hedge ineffectiveness on these interest rate swaps.

Accounting Standards Issued

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115*. SFAS No. 159 provides the option to report at fair value certain financial instruments that are not currently required or permitted to be measured at fair value. This option would be applied on an instrument by instrument basis. If elected, unrealized gains and losses on the affected financial instruments would be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective beginning January 1, 2008. We are currently assessing the provisions of SFAS No. 159; however, while the application of the fair value accounting would be optional, the impact of fair value accounting, if elected, could be material to our, or BGE's, financial results.

FSP FIN 39-1

In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, *Amendment of FASB Interpretation No. 39.* FSP FIN 39-1 permits an entity to report all derivatives recorded at fair value with any associated fair value cash collateral, which are with the same counterparty under a master netting arrangement, together in the balance sheet. Our wholesale competitive supply operation reports derivative amounts under master netting arrangements net in accordance with FIN 39, *Offsetting of Amounts Related to Certain Contracts*; however, we report fair value cash collateral separately from our derivative amounts. Under the provisions of this FSP, we must either report all derivatives recorded at fair value net with the associated fair value cash collateral or report all derivative amounts gross. The effects of FSP FIN 39-1 must be applied by adjusting all financial statements presented beginning January 1, 2008. We are currently evaluating the impact of this FSP; however, this FSP could have a material impact on our balance sheet presentation.

Accounting Standards Adopted

FIN 48

In July 2006, the FASB issued FIN 48. FIN 48 provides guidance for the recognition and measurement of an entity's uncertain tax positions. These are defined as positions taken in a previously filed tax return or positions expected to be taken in future tax returns and which result in, among other things, a permanent reduction of income taxes payable, a deferral of income taxes otherwise currently payable to future years, or a change in the expected ability to realize deferred tax assets. Under FIN 48, we are required to recognize the financial statement effects of tax positions if they meet a "more-likely-than-not" threshold. In evaluating items relative to this threshold, we must assess whether each tax position will be sustained based solely on its technical merits assuming examination by a taxing authority.

For those uncertain tax positions that we have recognized in our financial statements, we establish liabilities to reflect the portion of those positions we cannot conclude are "more likely than not" to be realized upon ultimate settlement. These are referred to as liabilities for unrecognized tax benefits under FIN 48. We recognize interest and penalties related to unrecognized tax benefits in "Income tax expense" in our Consolidated Statements of Income.

The adoption of FIN 48 on January 1, 2007, resulted in our recording a $7.3 million incremental liability for unrecognized tax benefits and a corresponding reduction in "Retained earnings" in our Consolidated Balance Sheets as a cumulative effect of change in accounting principle. We also reclassified $49.4 million from existing tax liabilities (primarily deferred income taxes) to the new FIN 48 liability for unrecognized tax benefits. Our resulting total $56.7 million FIN 48 liability for unrecognized tax benefits included $12.1 million of accrued interest and penalties.

Additionally, FIN 48 requires disclosure of total unrecognized tax benefits, regardless of whether or not these amounts are reflected in our balance sheet. We have $59.4 million of unrecognized tax benefits related to outstanding federal and state refund claims for which no tax benefit was previously provided in our financial statements because the claims do not meet the "more-likely-than-not" threshold. Included in this amount is $48.3 million of refund claims that have been disallowed by the applicable tax authorities for which we assess the probability of tax benefit recognition to be remote.

The following table summarizes our total unrecognized tax benefits at January 1, 2007:

At January 1, 2007

		(In millions)
Total liabilities reflected in our balance sheet for unrecognized tax benefits of $56.7 million less $12.1 million of interest and penalties	$	44.6
Other unrecognized tax benefits not reflected in our balance sheet		59.4
Total unrecognized tax benefits	$	104.0

During the nine months ended September 30, 2007, total unrecognized tax benefits increased approximately $20 million primarily due to increases in temporary differences related to deductions for repairs. There was no significant net change in tax expense as a result of these differences. The increases reflect tax positions expected to be taken in current year tax returns that are consistent with similar tax positions taken in prior years.

If the total amount of unrecognized tax benefits of $124.0 million as of September 30, 2007 were ultimately realized, our income tax expense would decrease by approximately $76.0 million. The $124.0 million includes the $48.3 million of disallowed refund claims discussed above.

We file income tax returns in the United States and foreign jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2002. The IRS commenced an examination of our U.S. income tax returns for 2002, 2003, and 2004 in the third quarter of 2005. We anticipate that these examinations will be completed by the end of 2007.

Recently, the IRS has proposed certain adjustments to our 2002-2004 deductions for repairs and casualty losses. We do not anticipate the adjustments, if any, would result in a material impact on our financial results. However, we anticipate that it is reasonably possible that we will make an additional payment in the range of $20 to $25 million by June 30, 2008, which will reduce our liabilities for unrecognized tax benefits.

The adoption of FIN 48 did not have a material impact on BGE's financial results.

Related Party Transactions 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 wholesale marketing, risk management, and trading operation supplied a substantial portion of BGE's market-based standard offer service obligation to residential electric customers through May 31, 2007, and will supply a portion of BGE's market-based standard offer service obligations for electric customers from June 1, 2007 through May 31, 2009.

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 September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Purchased energy	**$ 355.1**	$ 412.5	**$ 912.1**	$ 820.8

In addition, Constellation Energy charges BGE for the costs of certain corporate functions. Certain costs 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 the costs Constellation Energy charged to BGE in each period.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Charges to BGE	**$ 41.8**	$ 37.5	**$ 111.6**	$ 99.2

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. Under this arrangement, BGE had invested $261.8 million at September 30, 2007 and $60.6 million at December 31, 2006.

BGE's Consolidated Balance Sheets include intercompany amounts related to corporate functions performed at the Constellation Energy holding company, 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, and the participation of BGE's employees in the Constellation Energy defined benefit plans.

We believe our allocation methods are reasonable and approximate the costs that would be charged to unaffiliated entities.

Item 2. Management's Discussion

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 including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in the *Notes to Consolidated Financial Statements* on page 15.

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 in more detail in *Item 1 Business* section of our 2006 Annual Report on Form 10-K and we discuss the risks affecting our business in *Item 1A. Risk Factors* section on page 56.

Our 2006 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 segments,
- *Strategy* section,
- *Business Environment* section, including how regulation, weather, and other factors affect our business, and
- *Critical Accounting Policies* section.

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, and
- expected sources of cash for further capital expenditures.

As you read this discussion and analysis, refer to our Consolidated Statements of Income on page 3, which present the results of our operations for the quarters and nine months ended September 30, 2007 and 2006. 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 discuss our critical accounting policies. These are the accounting policies that are most important to the portrayal of our financial condition and results of operations and require management's most difficult, subjective, or complex judgment.

We highlight significant events that occurred in 2007 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

With the evolving regulatory environment surrounding customer choice, increasing competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 57 and in *Item 1A. Risk Factors* section on page 56. We discuss our market risks in the *Market Risk* section beginning on page 52.

In this section, we discuss in more detail events which have impacted our business during 2007.

Regulation by the Maryland PSC

In April 2007, Senate Bill 400 was enacted, which makes certain modifications to Senate Bill 1, which was enacted in June 2006. We discuss Senate Bill 1 in more detail in *Item 1. Business Electric Regulatory Matters and Competition* section of our 2006 Annual Report on Form 10-K. Pursuant to Senate Bill 400, the Maryland Public Service Commission (Maryland PSC) has retained a consultant and initiated several studies, including studies relating to stranded costs, the costs and benefits of various options for regulation, and the structure of the electric industry in Maryland. The Maryland PSC is required to submit an interim report by December 1, 2007 and a final report by December 1, 2008. We cannot at this time predict the outcome of these studies or their actual effect on our, or BGE's, financial results, but it could be material.

As required by Senate Bill 1, in May 2007, the Maryland PSC approved a plan allowing residential electric customers the option to defer the transition to market rates from June 1, 2007 to January 1, 2008. Customers participating in the plan will repay the deferred charges beginning April 1, 2008 through December 31, 2009 without interest. Only 4 percent of BGE's residential electric customers opted into the deferral plan, while the remaining 96 percent moved to full market rates effective June 1, 2007. The total amount deferred under this plan is expected to be approximately $6 million.

The Maryland PSC has made various inquiries relating to the relationship between Constellation Energy and BGE and the impact of that relationship on the rates paid by BGE residential electric customers. Hearings may also be conducted. We cannot at this time predict the outcome of these inquiries or any hearings that may be held or how such outcome may affect our, or BGE's, financial results, but it could be material.

Environmental Matters

Air Quality

National Ambient Air Quality Standards (NAAQS)

In June 2007, the United States Court of Appeals for the District of Columbia Circuit denied a petition by the Environmental Protection Agency (EPA) to rehear a Court decision finding that the EPA must impose fees on emissions sources that failed to achieve applicable ozone standards retroactive to November 2005. In September 2007, a number of parties petitioned the U.S. Supreme Court to hear an appeal. At this time, we cannot predict whether the Court will grant the petition. In addition, the exact method of computing these fees has not been established and will depend in part on state implementation regulations that have not been finalized. Consequently, we are unable to estimate the ultimate financial impact of the fees in light of the uncertainty surrounding the methodology that will be used in calculating the fees. However, any fees that are ultimately assessed could have a material impact on our financial results.

New Source Review

In April 2007, the U.S. Supreme Court issued a decision regarding the standard to be used to measure emissions when the EPA's new source review requirements are triggered but did not address when those requirements are triggered. We do not believe the Court's decision will have a material impact on our financial results.

Global Climate Change

In April 2007, the U.S. Supreme Court ruled that the EPA has authority to regulate carbon dioxide (CO_2) emissions from automobiles. Although the decision did not address CO_2 emissions from stationary sources such as power generation facilities, federal legislation or regulation addressing CO_2 emissions from other sources may now be more likely. We cannot predict the nature or timing of any CO_2 legislation or regulation, but any compliance costs we incur could have a material impact on our financial results.

Also in April 2007, Maryland became a full participant in the Northeast Regional Greenhouse Gas Initiative (RGGI). In October 2007, the Maryland Department of the Environment proposed auctioning 90% of CO_2 allowances associated with Maryland's power plants, which include plants owned by us, under RGGI. If this proposal is enacted, we could incur material costs to purchase CO_2 allowances necessary to offset emissions from our plants. We discuss RGGI in more detail in *Item 1 Business* section of our 2006 Annual Report on Form 10-K.

Water Quality

Water Intake Regulations

In response to a ruling by the United States Court of Appeals for the Second Circuit that the EPA's water intake regulations did not properly implement the Clean Water Act requirements in a number of areas, the EPA suspended the second phase of the regulations for existing facilities pending further rulemaking, and directed permitting authorities to use their best professional judgment to establish controls for cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. We continue to evaluate our compliance options in light of the court decision and the EPA's order. Until we determine our most viable option, we cannot estimate our compliance costs. However, those costs could be material.

Hazardous and Solid Waste

The Maryland Department of the Environment intends to issue regulations by the end of 2007 governing ash management in Maryland. Depending on the scope of any final regulations, our compliance costs could be material.

Capital Expenditures

As discussed in our 2006 Annual Report on Form 10-K, we expect to incur additional environmental capital expenditures to comply with air quality laws and regulations. Based on updated information from vendors, we expect our estimated environmental capital requirements to be approximately $170 million in 2007, $540 million in 2008, $360 million in 2009 and $40 million from 2010-2011.

Our estimates may change further as we implement our compliance plan. As discussed in our 2006 Annual Report on Form 10-K, our estimates of capital expenditures continue to be subject to significant uncertainties.

Critical Accounting Policies

We discuss our critical accounting policies in detail in our 2006 Annual Report on Form 10-K. Our critical accounting policies relate to derivative accounting, evaluation of assets for impairment and other than temporary decline in value, and asset retirement obligations. From time to time, we perform studies to update our nuclear decommissioning asset retirement obligations. During the third quarter of 2007, we completed site specific studies for all three of our nuclear sites in which we updated our estimate of the future cost of decommissioning our nuclear power plants. Based on the results of these studies, we recognized an approximately $124 million reduction in our asset retirement obligation. We discuss the reduction in our asset retirement obligation in the *Notes to Consolidated Financial Statements* beginning on page 12.

There are numerous key assumptions involved in estimating the future cost of nuclear decommissioning, which, in turn, are used to develop the related asset retirement obligation. The following are some of the more significant assumptions that were addressed in our 2007 studies:

- decommissioning methods and technologies,
- the timing of key activities and acceptance of spent fuel by the Department of Energy,
- cost-escalation assumptions for labor, materials and equipment, waste disposal, energy, transportation, and general inflation, and
- federal and state regulatory requirements.

In view of the significant number of assumptions underlying the decommissioning cost estimate and the long time horizons involved, our estimate of the future cost of decommissioning is likely to continue to change over time. For perspective, a 10% increase or decrease in our estimate of the future cost of nuclear decommissioning would produce an approximately $80 million change to our asset retirement obligation and an approximately $10 million change in our total annual amortization and accretion expenses.

Accounting Standards Issued and Adopted

We discuss recently issued and adopted accounting standards in the *Accounting Standards Issued* and *Accounting Standards Adopted* sections of the *Notes to Consolidated Financial Statements* beginning on page 23.

Events of 2007

Common Share Repurchase Program

In October 2007, our board of directors approved a common share repurchase program for up to $1 billion of our outstanding common stock. We discuss this common share repurchase program in more detail in the *Notes to Consolidated Financial Statements* on page 15.

Constellation Energy Partners LLC

We discuss the issuances of Constellation Energy Partners LLC equity and their impact on our financial results in more detail in the *Notes to Consolidated Financial Statements* on page 13.

Acquisitions

Working Interests in Gas Producing Fields

In March 2007, we acquired working interests in gas and oil producing fields. We discuss this acquisition in more detail in the *Notes to Consolidated Financial Statements* on page 13.

Contract and Portfolio Acquisitions

In June 2007, our wholesale marketing, risk management, and trading operation acquired a portfolio of energy contracts in the southeast region of the United States. We discuss this in more detail in the *Notes to Consolidated Financial Statements* beginning on page 13.

Cornerstone Energy

In July 2007, we acquired Cornerstone Energy, Inc. We discuss this acquisition in more detail in the *Notes to Consolidated Financial Statements* on page 14.

Shipping Joint Venture

In the third quarter of 2007, we made cash contributions totaling $44 million to a shipping joint venture in which we have a 50% ownership interest. We discuss this joint venture in more detail in the *Notes to Consolidated Financial Statements* on page 14.

Rate Stabilization Bonds

In 2007, BGE formed a special purpose bankruptcy-remote limited liability company to purchase rate stabilization property from BGE and to issue rate stabilization bonds. We discuss this entity and the related financing in more detail in the *Notes to Consolidated Financial Statements* on pages 11 and 17.

Electricite de France Joint Venture

In August 2007, we formed a joint venture, UniStar Nuclear Energy, LLC, with an affiliate of Electricite de France. We discuss this joint venture in more detail in the *Notes to Consolidated Financial Statements* on page 15.

Synthetic Fuel Tax Credits

As discussed in our 2006 Annual Report on Form 10-K, the Internal Revenue Code provides for a phase-out of synthetic fuel tax credits if average annual wellhead oil prices increase above certain levels. For 2007, we estimate the tax credit reduction would begin if the reference price exceeds approximately $56 per barrel and would be fully phased out if the reference price exceeds approximately $70 per barrel.

Based on forward market prices and volatilities and current production levels as of September 30, 2007, we estimate a 54% tax credit phase-out in 2007. We discuss the impact of synthetic fuel tax credits on our total income tax expense and effective tax rate in the *Notes to Consolidated Financial Statements* on page 18.

Based on forward market prices and volatilities and current production levels as of October 26, 2007, we currently estimate a 69% tax credit phase-out in 2007. However, the ultimate amount of tax credits phased-out for 2007, if any, is subject to change based on the actual reference price and production levels for the entire year.

Results of Operations for the Quarter and Nine Months Ended September 30, 2007 Compared with the Same Periods of 2006

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. We discuss changes in other income, fixed charges, and income taxes, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section beginning on page 46.

Overview

Results

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions, after-tax)			
Merchant energy	**$ 226.5**	$ 266.7	**$ 450.3**	$ 351.5
Regulated electric	**34.3**	42.8	**85.9**	96.3
Regulated gas	**(9.8)**	(7.3)	**18.2**	26.3
Other nonregulated	**(0.3)**	4.1	**9.9**	7.9
Income from Continuing Operations	**250.7**	306.3	**564.3**	482.0
Income (loss) from discontinued operations	**0.7**	18.1	**(0.9)**	49.5
Net Income	**$ 251.4**	$ 324.4	**$ 563.4**	$ 531.5
Other Items Included in Operations				
Non-qualifying hedges	**$ 1.9**	$ 35.9	**$ (6.0)**	$ 26.2
Impairment losses and other costs			**(12.2)**	
Workforce reduction costs		(13.1)	**(1.5)**	(14.4)
Merger-related costs		(2.5)		(10.0)
Total Other Items	**$ 1.9**	$ 20.3	**$ (19.7)**	$ 1.8

Certain prior-period amounts have been reclassified to conform with the current period's presentation.

Quarter Ended September 30, 2007

Our total net income for the quarter ended September 30, 2007 decreased $73.0 million, or $0.41 per share, compared to the same period of 2006 mostly because of the following:

We had lower earnings of $35.7 million after-tax from our facilities that produce synthetic fuel primarily due to a higher level of expected phase-out in tax credits. We discuss the impact of synthetic fuel tax credits from these facilities in more detail in the *Notes to Consolidated Financial Statements* on page 18.

We had lower earnings of approximately $19 million after-tax at our merchant energy business due to lower gross margin from the Mid-Atlantic Region. We discuss this decrease in gross margin in more detail in the *Mid-Atlantic Region* section on page 34.

We had lower earnings from discontinued operations of $17.4 million after-tax.

We had lower earnings of $17.3 million after-tax at our retail competitive supply operation due to lower gross margin and higher operating expenses. We discuss our retail gross margin in more detail in the *Competitive Supply* section beginning on page 34.

We had lower earnings of $11.0 million after-tax at our regulated businesses primarily due to higher operations and maintenance expenses and credits to residential customers required by Maryland's Senate Bill 1.

We had lower earnings of approximately $10 million after-tax at our wholesale competitive supply operations mostly due to higher operating expenses and the absence of earnings from our gas plants that were sold in December 2006, partially offset by higher gross margin. We discuss our mark-to-market and wholesale accrual results in more detail in the *Competitive Supply* section beginning on page 35.

These decreases were partially offset by the following:

We had higher earnings of approximately $24 million after-tax due to gains on the sales of equity by Constellation Energy Partners (CEP). We discuss these sales in more detail in the *Notes to Consolidated Financial Statements* on page 13.

We had higher earnings of approximately $15 million after-tax from an increase in other income mostly due to interest income resulting from a higher cash balance primarily from proceeds from the sale of gas-fired plants in December 2006, and lower fixed charges due to the repayment of $600 million of long-term debt in April 2007.

We had higher earnings of $13.1 million after-tax related to a lower level of workforce reduction costs.

Nine Months Ended September 30, 2007

Our total net income for the nine months ended September 30, 2007 increased $31.9 million, or $0.14 per share, compared to the same period of 2006 mostly because of the following:

We had higher earnings of approximately $108 million after-tax at our merchant energy business due to higher gross margin from the Mid-Atlantic Region. We discuss this increase in gross margin in more detail in the *Mid-Atlantic Region* section on page 34.

We had higher earnings of approximately $54 million after-tax from an increase in other income mostly due to interest income resulting from a higher cash balance primarily from proceeds from the sale of gas-fired plants in December 2006, and lower fixed charges due to the repayment of $600 million of long-term debt in April 2007.

We had higher earnings of approximately $31 million after-tax due to gains on the sales of equity by CEP. We discuss these sales in more detail in the *Notes to Consolidated Financial Statements* on page 13.

We had higher earnings of $12.9 million after-tax related to lower workforce reduction costs.

We had higher earnings of $10.0 million after-tax due to the absence of merger-related costs associated with our cancelled merger with FPL Group.

These increases were partially offset by the following:

We had lower earnings from discontinued operations of $50.4 million after-tax.

We had lower earnings of approximately $51 million after-tax at our wholesale competitive supply operations mostly due to higher operating expenses and slightly lower gross margin, including the absence of gross margin from our gas plants that were sold in December 2006. We discuss our mark-to-market and wholesale accrual results in more detail in the *Competitive Supply* section beginning on page 35.

We had lower earnings of $19.9 million after-tax at our retail competitive supply operation due primarily to higher operations expenses, partially offset by higher gross margin. We discuss our retail gross margin in more detail in the *Competitive Supply* section beginning on page 34.

We had higher costs of approximately $20 million after-tax at our generating facilities mostly due to higher expenses at our fossil plants.

We had lower earnings of $18.5 million after-tax at our regulated businesses primarily due to higher operations and maintenance expenses.

We had lower earnings due to a $12.2 million after-tax charge related to a cancelled wind development project. We discuss this charge in more detail in the *Notes to Consolidated Financial Statements* on page 12.

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

Merchant Energy Business

Background

Our merchant energy business is a competitive provider of energy solutions for various customers. We discuss the impact of deregulation on our merchant energy business in *Item 1. Business Competition* section of our 2006 Annual Report on Form 10-K.

Our merchant energy business focuses on delivery of physical, customer-oriented products to producers and consumers, manages the risk and optimizes the value of our owned generation assets, and uses our portfolio management and trading capabilities both to manage risk and to deploy risk capital to generate additional returns. We continue to identify and pursue opportunities which can generate additional returns through portfolio management and trading activities within our business. These opportunities have increased due to the significant growth in scale of our competitive supply operations.

We record merchant energy revenues and expenses in our financial results in different periods depending upon which portion of our business they affect. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and *Note 1* of our 2006 Annual Report on Form 10-K. We summarize our revenue and expense recognition policies as follows:

We record revenues as they are earned and fuel and purchased energy costs as they are incurred for contracts and activities subject to accrual accounting, including certain load-serving activities.

Prior to the settlement of the forecasted transaction being hedged, we record changes in the fair value of contracts designated as cash-flow hedges in other comprehensive income to the extent that the hedges are effective. We record the effective portion of the changes in fair value of hedges in earnings in the period the settlement of the hedged transaction occurs. We record the ineffective portion of the changes in fair value of hedges, if any, in earnings in the period in which the change occurs.

We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues or fuel and purchased energy expenses in the period in which the change occurs.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of certain contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our results in the *Competitive Supply Mark-to-Market* section beginning on page 36.

Our wholesale marketing, risk management, and trading operation actively transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of these activities, we trade energy and energy-related commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines, and may have a material impact on our financial results. We discuss the impact of our trading activities and value at risk in more detail in the *Competitive Supply Mark-to-Market* section beginning on page 36 and the *Market Risk* section beginning on page 52.

Results

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	2006	**2007**	2006
	(In millions)			
Revenues	**$ 5,275.9**	$ 5,008.7	**$ 14,113.7**	$ 12,999.9
Fuel and purchased energy expenses	**(4,319.2)**	(4,055.7)	**(11,808.0)**	(10.862.4)
Operating expenses	**(486.1)**	(367.3)	**(1,338.0)**	(1,146.3)
Impairment losses and other costs			**(20.2)**	
Workforce reduction costs		(21.7)	**(2.3)**	(23.9)
Merger-related costs		(2.5)		(8.8)
Depreciation, depletion, and amortization	**(66.9)**	(68.6)	**(197.7)**	(199.3)
Accretion of asset retirement obligations	**(16.0)**	(17.0)	**(51.9)**	(50.2)
Taxes other than income taxes	**(29.1)**	(31.3)	**(85.0)**	(90.9)
Income from Operations	**$ 358.6**	$ 444.6	**$ 610.6**	$ 618.1
Income from Continuing Operations (after- tax)	**$ 226.5**	$ 266.7	**$ 450.3**	$ 351.5
Income from discontinued operations (after- tax)	**0.7**	18.1	**(0.9)**	48.6
Net Income	**$ 227.2**	$ 284.8	**$ 449.4**	$ 400.1
Other Items Included in Operations (after-tax)				
Non-qualifying hedges	**$ 1.9**	$ 35.9	**$ (6.0)**	$ 26.2
Impairment losses and other costs			**(12.2)**	
Workforce reduction costs		(13.1)	**(1.5)**	(14.4)
Merger-related costs		(1.8)		(7.0)
Total Other Items	**$ 1.9**	$ 21.0	**$ (19.7)**	$ 4.8

Certain prior-period amounts have been reclassified to conform with the current period's presentation. 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 16 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages the revenues we realize from the sale of energy to our customers and our costs of procuring fuel and energy. As previously discussed, our merchant energy business uses either accrual or mark-to-market accounting to record our revenues and expenses. Mark-to-market results reflect the net impact of amounts recorded in either revenues or fuel and purchased energy expenses to recognize changes in fair value of derivative contracts subject to mark-to-market accounting during the reporting period.

The difference between revenues and fuel and purchased energy expenses, including all direct expenses, is the gross margin of our merchant energy business, and this measure is a useful tool for assessing the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in gross margin between periods. In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

We analyze our merchant energy gross margin in the following categories because of the risk profile of each category, differences in the revenue sources, and the nature of fuel and purchased energy expenses. With the exception of a portion of our competitive supply activities that we are required to account for using the mark-to-market method of accounting, all of these activities are accounted for on an accrual basis.

- Mid-Atlantic Region our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM region. This also includes active portfolio management of the generating assets and other physical and financial contractual arrangements, as well as other PJM competitive supply activities.
- Plants with Power Purchase Agreements our Nine Mile Point and Ginna nuclear generating facilities.
- Wholesale Competitive Supply our marketing, risk management, and trading operation that provides energy products and services (including portfolio management and trading activities) primarily to distribution utilities, power generators, and other wholesale customers. We also provide global energy, logistics, and upstream and downstream natural gas services.
- Retail Competitive Supply our operation that provides electric and gas energy products and services to commercial, industrial, and governmental customers.
- Other our investments in qualifying facilities and domestic power projects and our generation operations and maintenance services.

We provide a summary of our revenues, fuel and purchased energy expenses, and gross margin as follows:

	Quarter Ended September 30,				Nine Months Ended September 30,			
	2007		2006		2007		2006	
	(Dollar amounts in millions)							
Revenues:								
Mid-Atlantic Region	**$ 1,364.6**		$ 1,002.2		**$ 2,596.8**		$ 2,119.2	
Plants with Power Purchase Agreements	**204.1**		214.7		**517.6**		518.0	
Competitive Supply								
Retail	**2,291.0**		2,094.8		**6,671.2**		5,964.9	
Wholesale	**1,387.2**		1,668.9		**4,274.6**		4,339.3	
Other	**29.0**		28.1		**53.5**		58.5	
Total	**$ 5,275.9**		$ 5,008.7		**$ 14,113.7**		$ 12,999.9	
Fuel and purchased energy expenses:								
Mid-Atlantic Region	**$ (998.9)**		$ (605.3)		**$ (1,669.7)**		$ (1,370.3)	
Plants with Power Purchase Agreements	**(20.8)**		(16.5)		**(58.4)**		(51.3)	
Competitive Supply								
Retail	**(2,172.1)**		(1,964.9)		**(6,360.9)**		(5,667.6)	
Wholesale	**(1,127.4)**		(1,469.0)		**(3,719.0)**		(3,773.2)	
Other								
Total	**$ (4,319.2)**		$ (4,055.7)		**$ (11,808.0)**		$ (10,862.4)	
		% of Total		**% of Total**		**% of Total**		**% of Total**
Gross Margin:								
Mid-Atlantic Region	**$ 365.7**	**38%**	$ 396.9	41%	**$ 927.1**	**40%**	$ 748.9	35%
Plants with Power Purchase Agreements	**183.3**	**19**	198.2	21	**459.2**	**20**	466.7	22
Competitive Supply								
Retail	**118.9**	**12**	129.9	14	**310.3**	**13**	297.3	14
Wholesale	**259.8**	**28**	199.9	21	**555.6**	**25**	566.1	26
Other	**29.0**	**3**	28.1	3	**53.5**	**2**	58.5	3
Total	**$ 956.7**	**100%**	$ 953.0	100%	**$ 2,305.7**	**100%**	$ 2,137.5	100%

	Quarter Ended September 30,	**Nine Months Ended September 30,**

Certain prior-period amounts have been reclassified to conform with the current period's presentation. Revenues for the nine months ended September 30, 2007 reflect the reclassification of $111.7 million relating to the six months ended June 30, 2007 to conform with the current period presentation. Prior year reclassifications relate to operations that have been classified as discontinued operations.

Merchant energy gross margin for the quarter and nine months ended September 30, 2007 includes the effects of market price changes on derivatives designated as cash-flow and fair value hedges. These market price changes had two primary impacts on the quarter and nine months ended September 30, 2007:

We experienced a significant increase in the level of ineffectiveness associated with derivatives that qualified for hedge accounting treatment.

Additionally, we were required to discontinue the application of hedge accounting treatment for certain derivatives due to insufficient price correlation between the hedge and the risk being hedged. As a result, the full change in the fair value of these derivatives has been recorded in earnings.

The merchant energy gross margin impact for the quarter and nine months ended September 30, 2007 from the effect of market price changes on derivatives designated as cash-flow and fair value hedges is summarized as follows:

	Quarter Ended September 30, 2007	Nine Months Ended September 30, 2007
	(in millions)	
Ineffectiveness on derivatives that qualified for hedge accounting treatment	$ 30.9	$ 1.7
Effect of reduced price correlation on derivatives that did not qualify for hedge accounting treatment		
Derivatives that remain designated as hedges prospectively	9.1	(7.3)
Derivatives not eligible for designation as hedges prospectively	(14.1)	(51.1)
Total	$ 25.9	$ (56.7)

We discuss below the impact of these items on the applicable categories of merchant energy gross margin for the quarter and nine months ended September 30, 2007 compared to the same periods of 2006. We discuss our hedging activities in more detail in the *Notes to Consolidated Financials* beginning on page 22.

Mid-Atlantic Region

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Revenues	**$ 1,364.6**	$ 1,002.2	**$ 2,596.8**	$ 2,119.2
Fuel and purchased energy expenses	**(998.9)**	(605.3)	**(1,669.7)**	(1,370.3)
Gross margin	**$ 365.7**	$ 396.9	**$ 927.1**	$ 748.9

The decrease in gross margin of $31.2 million during the quarter ended September 30, 2007 compared to the same period of 2006 is primarily due to approximately $50 million related to lower volumes served, partially offset by $19 million related to the favorable impact of gains on certain cash-flow hedges. The favorable impact of gains recognized on cash-flow hedges is due to ineffectiveness and certain cash-flow hedges that did not qualify for hedge accounting during the quarter ended September 30, 2007 compared to the same period of 2006.

The $178.2 million increase in gross margin during the nine months ended September 30, 2007 compared to the same period of 2006 is primarily due to approximately $244 million in higher margins on new and existing contracts. The increase in gross margin was partially offset by the following:

- the unfavorable impact of approximately $25 million related to losses recognized on cash-flow hedges due to ineffectiveness and certain cash-flow hedges that did not qualify for hedge accounting during the quarter, and
- absence of competitive transition charge (CTC) revenue of $41.0 million, which ended June 30, 2006.

Plants with Power Purchase Agreements

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Revenues	**$ 204.1**	$ 214.7	**$ 517.6**	$ 518.0
Fuel and purchased energy expenses	**(20.8)**	(16.5)	**(58.4)**	(51.3)
Gross margin	**$ 183.3**	$ 198.2	**$ 459.2**	$ 466.7

Gross margin from our Plants with Power Purchase Agreements was $14.9 million lower primarily due to lower prices for the output from our facilities, partially offset by higher output from our Ginna nuclear facility for the quarter ended September 30, 2007. Gross margin from our Plants with Power Purchase Agreements was $7.5 million lower primarily due to higher nuclear fuel amortization expense and lower prices for the output from our facilities, partially offset by higher output from our Ginna nuclear facility for the nine months ended September 30, 2007. During the fourth quarter of 2006, we completed a planned outage at Ginna, which included increasing the plant capacity from 498 megawatts to the current 581 megawatts.

Competitive Supply

Retail

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Accrual revenues	**$ 2,288.1**	$ 2,083.3	**$ 6,688.3**	$ 5,943.2
Fuel and purchased energy expenses	**(2,172.1)**	(1,981.3)	**(6,360.9)**	(5,664.8)
Retail accrual activities	**116.0**	102.0	**327.4**	278.4
Mark-to-market activities	**2.9**	27.9	**(17.1)**	18.9
Gross margin	**$ 118.9**	$ 129.9	**$ 310.3**	$ 297.3

The $14.0 million increase in accrual gross margin from our retail competitive supply activities during the quarter ended September 30, 2007 compared to the same period of 2006 is primarily due to approximately $35 million of higher gross margin mostly from lower costs to serve load in our retail electric operations. This increase in gross margin was partially offset by approximately $21 million in losses at our retail gas operations recognized on cash-flow hedges due to ineffectiveness and certain cash-flow hedges that did not qualify for hedge accounting during the quarter ended September 30, 2007 compared to the same period of 2006.

The $49.0 million increase in accrual gross margin from our retail competitive supply activities during the nine months ended September 30, 2007 compared to the same period of 2006 is primarily due to approximately $85 million related to the positive impact of higher volumes served at higher contract rates per megawatt hour and lower costs to serve load in our retail electric operations. This increase in gross margin was partially offset by approximately $36 million related to losses at our retail gas operations recognized during the nine months ended September 30, 2007 on hedges due to ineffectiveness and certain hedges that did not qualify for hedge accounting compared to the same period of 2006.

Wholesale

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
		(In millions)		
Accrual revenues	**$ 1,293.4**	$ 1,565.1	**$ 4,050.1**	$ 4,032.8
Fuel and purchased energy expenses	**(1,127.4)**	(1,469.0)	**(3,719.0)**	(3,773.2)
Wholesale accrual activities	**166.0**	96.1	**331.1**	259.6
Mark-to-market revenues	**93.8**	103.8	**224.5**	306.5
Gross margin	**$ 259.8**	$ 199.9	**$ 555.6**	$ 566.1

Our wholesale marketing, risk management, and trading operation had $69.9 million of higher accrual gross margin during the quarter ended September 30, 2007 compared to the same period of 2006 primarily due to:

- approximately $87 million from new contracts executed, including the portfolio of contracts acquired in the southeast region as discussed in more detail in the *Notes to Consolidated Financial Statements* beginning on page 13, and higher gross margin associated with existing contracts, partially offset by the absence of gross margin associated with the gas plants that were sold in December 2006, and

- approximately $23 million related to gains recognized on cash-flow hedges due to ineffectiveness and certain cash-flow hedges that did not qualify for hedge accounting during the quarter ended September 30, 2007. We discuss this in more detail beginning on page 33.

These increases in gross margin were partially offset by lower gross margin related to contract terminations and sales of approximately $40 million during the quarter ended September 30, 2007 compared to the same period of 2006.

Our wholesale marketing, risk management, and trading operation had $71.5 million of higher accrual gross margin during the nine months ended September 30, 2007 compared to the same period of 2006 primarily due to approximately $146 million from new contracts executed, including the portfolio of contracts acquired in the southeast region as discussed in more detail in the *Notes to Consolidated Financial Statements* beginning on page 13, and higher gross margin associated with existing contracts, partially offset by the absence of gross margin associated with the gas plants that were sold in December 2006.

This increase in gross margin was partially offset by lower gross margin related to contract terminations and sales of approximately $40 million during the nine months ended September 30, 2007 compared to the same period of 2006 and approximately $34 million in losses recorded during the quarter ended March 31, 2007 for amounts reclassified from "Accumulated other comprehensive loss" to earnings related to:

the April 2007 CEP equity issuance and subsequent deconsolidation, as discussed in more detail in the *Notes to Consolidated Financial Statements* on page 13. We determined that the hedged forecasted sales were probable of not occurring, which resulted in the reclassification of losses from "Accumulated other comprehensive loss" into earnings.

certain amended nonderivative contracts such that the new contracts are accounted for as mark-to-market. This resulted in the recognition of losses from cash-flow hedges previously deferred in "Accumulated other comprehensive loss" due to the forecasted transaction affecting earnings. We discuss these contracts in more detail on the next page.

Mark-to-Market

Mark-to-market results include net gains and losses from origination, trading, and risk management 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 2006 Annual Report on Form 10-K.

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market earnings will fluctuate. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Market Risk* section beginning on page 52. The primary factors that cause fluctuations in our mark-to-market results are:

- the number, size, and profitability of new transactions, including termination or restructuring of existing contracts,
- the number and size of our open derivative positions, and
- changes in the level and volatility of forward commodity prices and interest rates.

Mark-to-market results were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Unrealized mark-to-market results				
Origination gains	**$ 4.3**	$ 3.6	**$ 37.4**	$ 9.6
Risk management and trading mark- to-market				
Unrealized changes in fair value	**92.4**	128.1	**170.0**	315.8
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(21.3)**	(95.4)	**(189.2)**	(324.3)
Total risk management and trading mark-to-market	**71.1**	32.7	**(19.2)**	(8.5)
Total unrealized mark-to- market*	**75.4**	36.3	**18.2**	1.1
Realized mark-to-market	**21.3**	95.4	**189.2**	324.3
Total mark-to-market results	**$ 96.7**	$ 131.7	**$ 207.4**	$ 325.4

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

Origination gains arise primarily from contracts that our wholesale marketing, risk management, and trading operation structures to meet the risk management needs of our customers or relate to our trading activities. Transactions that result in origination gains may be unique and provide the potential for individually significant revenues and gains from a single transaction.

Origination gains represent the initial fair value recognized on these transactions. The recognition of origination gains is dependent on sufficient observable market data that validates the initial fair value of the contract. Liquidity and market conditions impact our ability to identify sufficient, objective market-price information to permit recognition of origination gains. As a result, while our strategy and competitive position provide the opportunity to continue to originate such transactions, the level of origination gains we are able to recognize may vary from period to period as a result of the number, size, and market-price transparency of the individual transactions executed in any period.

During the first nine months of 2007, our wholesale marketing, risk management, and trading operation amended certain nonderivative power sales contracts such that the new contracts are derivatives subject to mark-to-market accounting under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*. Simultaneous with the amending of the nonderivative contracts, we executed at current market prices several new offsetting derivative power purchase contracts subject to mark-to-market accounting. The combination of these transactions resulted in substantially all of the origination gains presented for the first nine months of 2007 in the table on the previous page, as well as mitigated our risk exposure under the amended contracts.

The origination gain from these transactions was partially offset by approximately $12 million of losses in our accrual portfolio due to the reclassification of losses related to cash-flow hedges previously established for the amended nonderivative contracts from "Accumulated other comprehensive loss" into earnings as discussed in our *Competitive Supply-Wholesale Accrual* section on the previous page. In the absence of these transactions, the origination gain and the losses associated with cash-flow hedges would have been recognized over the remaining term of the contracts, which extended through the first quarter of 2009.

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 recognition of gains associated with decreases in the close-out adjustment when we are able to obtain sufficient market price information. In addition, we use derivative contracts subject to mark-to-market accounting to manage our exposure to changes in market prices primarily as a result of our gas transportation and storage activities, while in general the underlying physical transactions related to our gas 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.

Total mark-to-market results decreased $35.0 million during the quarter ended September 30, 2007 compared to the same period of 2006 mostly because of a decrease in unrealized changes in fair value of approximately $36 million, primarily due to approximately $56 million lower mark-to-market results related to the impact of certain economic hedges primarily related to gas transportation and storage contracts that do not qualify for or are not designated as cash-flow hedges under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*, partially offset by higher earnings of $21.7 million for the favorable impact related to changes in the close-out adjustment.

Total mark-to-market results decreased $118.0 million during the nine months ended September 30, 2007 compared to the same period of 2006 mostly because of a decrease in unrealized changes in fair value of approximately $146 million, partially offset by the $28 million increase in origination gains previously discussed. The $146 million decrease in unrealized changes in fair value was a result of:

- a less favorable price environment resulting in lower gains of approximately $136 million,
- approximately $53 million from lower mark-to-market results related to the impact of certain economic hedges primarily related to gas transportation and storage contracts, and
- these decreases were partially offset by a $42.8 million favorable impact related to changes in the close-out adjustment.

The close-out adjustments are determined by the change in open positions, new transactions where we did not have observable market price information, and existing transactions where we have now observed sufficient market price information and/or we realized cash flows since the transactions' inception. We discuss the close-out adjustment in more detail in the *Critical Accounting Policies* section of our 2006 Annual Report on Form 10-K.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts subject to mark-to-market accounting and consisted of the following:

	September 30, 2007	December 31, 2006
	(In millions)	
Current Assets	**$ 963.8**	$ 1,294.8
Noncurrent Assets	**699.9**	623.4
Total Assets	**1,663.7**	1,918.2
Current Liabilities	**687.1**	1,071.7
Noncurrent Liabilities	**406.8**	392.4
Total Liabilities	**1,093.9**	1,464.1
Net mark-to-market energy asset	**$ 569.8**	$ 454.1

The following are the primary sources of the change in the net mark-to-market energy asset during the quarter and nine months ended September 30, 2007:

	Quarter Ended September 30, 2007		Nine Months Ended September 30, 2007	
	(in millions)			
Fair value beginning of period		$ 532.5		$ 454.1
Changes in fair value recorded in earnings				
Origination gains	$ 4.3		$ 37.4	
Unrealized changes in fair value	92.4		170.0	
Changes in valuation techniques				
Reclassification of settled contracts to realized	(21.3)		(189.2)	
Total changes in fair value recorded in earnings		75.4		18.2
Changes in value of exchange-listed futures and options		39.6		48.2
Net change in premiums on options		(77.2)		10.7
Contracts acquired		(5.1)		88.5
Other changes in fair value		4.6		(49.9)
Fair value at end of period		$ 569.8		$ 569.8

Changes in the net mark-to-market energy asset that affected earnings were as follows:

Origination gains represent the initial unrealized fair value at the time these contracts are executed to the extent permitted by applicable accounting rules.

Unrealized changes in fair value represent unrealized changes in commodity prices, the volatility of options on commodities, the time value of options, and other valuation adjustments.

Changes in valuation techniques represent improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to more accurately reflect the fair value of our contracts.

Reclassification of settled contracts to realized represent the portion of previously unrealized amounts settled during the period and recorded as realized revenues.

The net mark-to-market energy asset also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income:

Changes in value of exchange-listed futures and options are adjustments to remove unrealized revenue from exchange-traded contracts that are included in risk management revenues. The fair value of these contracts is recorded in "Accounts receivable" rather than "Mark-to-market energy assets" in our Consolidated Balance Sheets because these amounts are settled through our margin account with a third-party broker.

Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net mark-to-market energy asset and premiums on options sold as a decrease in the net mark-to-market energy asset.

Contracts acquired represents the initial fair value of acquired derivative contracts recorded in "Mark-to-market energy assets and liabilities" in our Consolidated Balance Sheets.

Other changes in fair value include transfers between mark-to-market energy assets and liabilities and risk management assets and liabilities resulting from the designation and de-designation of cash-flow hedges.

The settlement terms of the net mark-to-market energy asset and sources of fair value as of September 30, 2007 are as follows:

	Settlement Term							
	2007	2008	2009	2010	2011	2012	Thereafter	Fair Value
	(In millions)							
Prices provided by external sources[1]	$ 146.3	$ 222.7	$ 5.2	$ (24.1)	$ (46.0)	$ (9.8)	$ 1.5	$ 295.8
Prices based on models	16.2	(3.1)	76.2	75.0	95.3	13.1	1.3	274.0
Total net mark-to-market energy asset	$ 162.5	$ 219.6	$ 81.4	$ 50.9	$ 49.3	$ 3.3	$ 2.8	$ 569.8

(1) *Includes contracts actively quoted and contracts valued from other external sources.*

We manage our mark-to-market risk on a portfolio basis based upon the delivery period of our contracts and the individual components of the risks within each contract. Accordingly, we record and manage the energy purchase and sale obligations under our contracts in separate components based upon the commodity (e.g., electricity or gas), the product (e.g., electricity for delivery during peak or off-peak hours), the delivery location (e.g., by region), the risk profile (e.g., forward or option), and the delivery period (e.g., by month and year).

Consistent with our risk management practices, we have presented the information in the table on the previous page based upon the ability to obtain reliable prices for components of the risks in our contracts from external price sources rather than on a contract-by-contract basis. Thus, the portion of long-term contracts that is valued using external price sources is presented under the caption "prices provided by external sources." This is consistent with how we manage our risk, and we believe it provides the best indication of the basis for the valuation of our portfolio. Since we manage our risk on a portfolio basis rather than contract-by-contract, it is not practicable to determine separately the portion of long-term contracts that is included in each valuation category. We describe the commodities, products, and delivery periods included in each valuation category in detail below.

The amounts for which fair value is determined using prices provided by external sources represent the portion of forward, swap, and option contracts for which price quotations are available through brokers or over-the-counter transactions. The term for which such price information is available varies by commodity, region, and product. The fair values included in this category are the following portions of our contracts:

- forward and swap purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2010, but up to 2012, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2008, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms primarily through 2007, but up to 2008, depending upon the region,
- forward and swap purchases and sales of natural gas, coal, and oil for delivery terms primarily through 2011, and
- options for the purchase and sale of natural gas, coal, and oil for delivery terms through 2008.

The remainder of the net mark-to-market energy asset is valued using models. The portion of contracts for which such techniques are used includes standard products for which external prices are not available and customized products that are valued using modeling techniques to determine expected future market prices, contract quantities, or both.

Modeling techniques include estimating the present value of cash flows based upon underlying contractual terms and incorporate, where appropriate, option pricing models and statistical and simulation procedures. Inputs to the models include:

- observable market prices,
- estimated market prices in the absence of quoted market prices,
- the risk-free market discount rate,
- volatility factors,
- estimated correlation of energy commodity prices, and
- expected generation profiles of specific regions.

Additionally, we incorporate counterparty-specific credit quality and factors for market price and volatility uncertainty and other risks in our valuation. The inputs and factors used to determine fair value reflect management's best estimates.

The electricity, fuel, and other contracts we hold have varying terms to maturity, ranging from contracts for delivery the next hour to contracts with terms of ten years or more. Because an active, liquid electricity futures market comparable to that for other commodities has not developed, the majority of contracts used in the wholesale marketing, risk management, and trading operation are direct contracts between market participants and are not exchange-traded or financially settling contracts that can be readily liquidated in their entirety through an exchange or other market mechanism. Consequently, we and other market participants generally realize the value of these contracts as cash flows become due or payable under the terms of the contracts rather than through selling or liquidating the contracts themselves.

Consistent with our risk management practices, the amounts shown in the table on the previous page as being valued using prices from external sources include the portion of long-term contracts for which we can obtain reliable prices from external sources. The remaining portions of these long-term contracts are shown in the table as being valued using models. In order to realize the entire value of a long-term contract in a single transaction, we would need to sell or assign the entire contract. If we were to sell or assign any of our long-term contracts in their entirety, we may not realize the entire value reflected in the table. However, based upon the nature of the wholesale marketing, risk management, and trading operation, we expect to realize the value of these contracts, as well as any contracts we may enter into in the future to manage our risk, over time as the contracts and related hedges settle in accordance with their terms. Generally, we do not expect to realize the value of these contracts and related hedges by selling or assigning the contracts themselves in total.

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of September 30, 2007 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

Management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

In 2006, the Financial Accounting Standards Board issued SFAS No. 157, *Fair Value Measurements*, that will impact our accounting for derivative instruments. We discuss this in more detail in *Note 1* of our 2006 Annual Report on Form 10-K.

Risk Management Assets and Liabilities

We record derivatives that qualify for designation as hedges under SFAS No. 133 in "Risk management assets and liabilities" in our Consolidated Balance Sheets. Our risk management assets and liabilities consisted of the following:

	September 30, 2007	December 31, 2006
	(In millions)	
Current Assets	**$ 165.1**	$ 261.7
Noncurrent Assets	**449.2**	325.7
Total Assets	**614.3**	587.4
Current Liabilities	**840.8**	1,340.0
Noncurrent Liabilities	**802.3**	707.3
Total Liabilities	**1,643.1**	2,047.3
Net risk management liability	**$ (1,028.8)**	$ (1,459.9)

The decrease in our net risk management liability since December 31, 2006 of $431.1 million was due primarily to an approximate $264 million change in our cash-flow hedge positions, which include both increases in power prices that increased the fair value of our cash-flow hedge positions and settlements of cash-flow hedges during the nine months ended September 30, 2007, and approximately $167 million of net cash-flow hedge assets acquired as part of a contract and portfolio acquisition in June 2007. We discuss this contract and portfolio acquisition in more detail in the *Notes to Consolidated Financial Statements* beginning on page 13.

Other

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(In millions)			
Revenues	**$ 29.0**	$ 28.1	**$ 53.5**	$ 58.5

Our merchant energy business holds up to a 50% voting interest in 24 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 24 projects, 17 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, and fuel processing projects provide sufficient positive cash flows to recover our investments. We continuously monitor issues that potentially could impact future profitability of these investments, including environmental and legislative initiatives. We discuss the impact of subsidies from the State of California in more detail in the *Merchant Energy Business Other* section in our 2006 Annual Report on Form 10-K.

We discuss certain risks and uncertainties in more detail in the *Forward Looking Statements* section on page 57 and in *Item 1A. Risk Factors* section on page 56. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired under the provisions of Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock*.

Operating Expenses

Our merchant energy business operating expenses increased $118.8 million during the quarter ended September 30, 2007 compared to the same period of 2006 mostly due to the following:

- an increase at our competitive supply operation totaling $90.7 million primarily related to the continued growth of this operation and higher compensation and benefit costs, and
- an increase of $12.1 million at our generating facilities reflecting higher expenses at our fossil plants, which included approximately $4 million in expenses related to the consent decree with the Maryland Department of the Environment, and approximately $2 million due to the growth in our business activities related to new nuclear development. We discuss the consent decree in more detail in the *Notes to Consolidated Financial Statements* on page 21.

Our merchant energy business operating expenses increased $191.7 million during the nine months ended September 30, 2007 compared to the same period of 2006 mostly due to the following:

- an increase at our competitive supply operations totaling $138.2 million primarily related to the continued growth of this operation and higher compensation and benefit costs, and
- an increase of $32.9 million at our generating facilities which included higher expenses of approximately $10 million at our fossil plants, approximately $6 million in higher costs related to new nuclear development, and expenses of approximately $4 million related to the consent decree with the Maryland Department of the Environment. We discuss the consent decree in more detail in the *Notes to Consolidated Financial Statements* on page 21.

Impairment Losses and Other Costs

During the nine months ended September 30, 2007, our merchant energy business recorded a $20.2 million charge associated with a cancelled wind development project. We discuss the charge in more detail in the *Notes to Consolidated Financial Statements* on page 12.

Workforce Reduction Costs

During the nine months ended September 30, 2007, our merchant energy business recognized expenses, net of reimbursement from co-owners, of $2.3 million associated with our workforce reduction efforts at our Nine Mile Point nuclear facility. We discuss the workforce reduction in more detail in the *Notes to Consolidated Financial Statements* on page 12.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $5.9 million during the nine months ended September 30, 2007 compared to the same period of 2006 primarily due to $4.7 million lower gross receipts tax at our retail competitive supply operation and a $3.1 million decrease due to the sale of our gas-fired plants. These decreases are partially offset by an increase of $2.7 million mostly due to growth of our upstream gas business.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section of our 2006 Annual Report on Form 10-K.

Results

	Quarter Ended September 30, 2007	Quarter Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions)			
Revenues	**$ 778.2**	$ 649.9	**$ 1,837.3**	$ 1,652.6
Electricity purchased for resale expenses	**(522.6)**	(391.1)	**(1,117.7)**	(933.8)
Operations and maintenance expenses	**(96.7)**	(89.3)	**(274.9)**	(258.9)
Merger-related costs		(0.6)		(2.3)
Depreciation and amortization	**(46.8)**	(45.6)	**(140.5)**	(137.1)
Taxes other than income taxes	**(36.1)**	(34.7)	**(105.8)**	(101.5)
Income from Operations	**$ 76.0**	$ 88.6	**$ 198.4**	$ 219.0
Net Income	**$ 34.3**	$ 42.8	**$ 85.9**	$ 96.3
Other Items Included in Operations (after-tax):				
Merger-related costs	**$**	$ (0.5)	**$**	$ (2.0)

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 16 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income from the regulated electric business decreased $8.5 million during the quarter ended September 30, 2007 compared to the same period of 2006, mostly due to increased operations and maintenance expenses of $4.5 million after-tax and decreased revenue less electricity purchased for resale expenses of $2.0 million after-tax reflecting credits to residential customers required by Maryland's Senate Bill 1.

Net income from the regulated electric business decreased $10.4 million during the nine months ended September 30, 2007 compared to the same period of 2006, primarily due to increased operations and maintenance expenses of $9.8 million after-tax.

Electric Revenues

The changes in electric revenues in 2007 compared to 2006 were caused by:

	Quarter Ended September 30, 2007 vs. 2006	Nine Months Ended September 30, 2007 vs. 2006
	(In millions)	
Distribution volumes	$ 5.4	$ 10.2
Standard offer service	(57.4)	270.3
Rate stabilization credits	169.8	(111.0)
Rate stabilization recovery	18.7	24.0
Financing credit	(3.8)	(4.5)
Senate Bill 1 credits	(10.6)	(21.6)
Total change in electric revenues from electric system sales	122.1	167.4
Other	6.2	17.3
Total change in electric revenues	$ 128.3	$ 184.7

	Quarter Ended September 30, 2007 vs. 2006	Nine Months Ended September 30, 2007 vs. 2006

Distribution Volumes

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

The percentage changes in our distribution volumes, by type of customer, in 2007 compared to 2006 were:

	Quarter Ended September 30, 2007 vs. 2006	Nine Months Ended September 30, 2007 vs. 2006
Residential	0.3%	5.3%
Commercial	(1.5)	2.5
Industrial	2.2	(2.6)

During the quarter ended September 30, 2007 compared to the same period of 2006, we distributed essentially the same amount of electricity to residential customers. We distributed less electricity to commercial customers due to milder weather and decreased usage per customer partially offset by an increased number of customers. We distributed more electricity to industrial customers primarily due to increased usage per customer.

During the nine months ended September 30, 2007 compared to the same period of 2006, we distributed more electricity to residential and commercial customers due to increased usage per customer, colder winter weather, and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer, partially offset by an increased number of customers.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier. We discuss the provisions of Senate Bill 1 related to residential electric rates in the *Item 1. Business Electric Regulatory Matters and Competition* section of our 2006 Annual Report on Form 10-K and recent developments related to residential electric rates in the *Regulation by the Maryland PSC* section beginning on page 26.

Standard offer service revenues decreased during the quarter ended September 30, 2007 compared to the same period of 2006 due to lower standard offer service volumes due to commercial and industrial customers switching to alternative suppliers and a decrease in the standard offer service rates.

Standard offer service revenues increased during the nine months ended September 30, 2007 compared to the same period of 2006 due to higher standard offer service volumes and an increase in the standard offer service rates following the expiration of residential rate freeze service in July 2006.

Rate Stabilization Credits

As a result of Senate Bill 1, we were required to defer from July 1, 2006 until May 31, 2007 a portion of the full market rate increase resulting from the expiration of the residential rate freeze. In addition, we offered a plan allowing residential customers the option to defer the transition to market rates from June 1, 2007 until January 1, 2008. Based on the number of customers electing to defer the transition to market rates from June 1, 2007 until January 1, 2008, the total amount deferred under this plan is expected to be approximately $6 million.

During the quarter ended September 30, 2007 compared to the same period of 2006, the amount of rate stabilization credits provided to residential electric customers substantially decreased and thereby increased revenues due to the expiration of the rate stabilization plan which began on July 1, 2006 and ended on May 31, 2007, partially offset by additional credits given to residential electric customers in the current quarter who elected to defer the transition to market rates from June 1, 2007 until January 1, 2008.

During the nine months ended September 30, 2007 compared to the same period of 2006, the amount of rate stabilization credits provided to residential electric customers increased and thereby reduced revenues as required by Senate Bill 1.

Rate Stabilization Recovery

Recovery of the amounts deferred under the rate stabilization plan that ended on May 31, 2007 began in late June 2007.

Financing Credits

Concurrent with the recovery of the deferred amounts related to the rate stabilization plan, we are providing credits to residential customers to compensate them primarily for income tax benefits associated with the financing of the deferred amounts with rate stabilization bonds. We discuss the rate stabilization bonds in more detail in the *Notes to Consolidated Financial Statements* on page 17.

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 ratepayers for the decommissioning of our Calvert Cliffs nuclear power plant and to suspend collection of the residential return component of the Provider of Last Resort (POLR) administrative charge collected through residential POLR 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 POLR administration charge in POLR rates and to provide all residential electric customers a credit for the residential return component of the administrative charge.

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.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006

	Quarter Ended September 30,		Nine Months Ended September 30,	
	(In millions)			
Actual costs	**$ 508.4**	$ 565.5	**$ 1,379.1**	$ 1,108.2
Deferral under rate stabilization plans	**(4.5)**	(174.4)	**(285.4)**	(174.4)
Recovery under rate stabilization plans	**18.7**		**24.0**	
Electricity purchased for resale	**$ 522.6**	$ 391.1	**$ 1,117.7**	$ 933.8

Actual Costs

BGE's actual costs for electricity purchased for resale decreased $57.1 million during the quarter ended September 30, 2007 in comparison with the same period in 2006 as a result of lower volumes mostly due to commercial and industrial customers switching to alternate suppliers and lower contract prices to purchase electricity for our residential customers.

BGE's actual costs for electricity purchased for resale increased $270.9 million for the nine months ended September 30, 2007 compared to the same period of 2006 primarily due to higher contract prices to purchase electricity for our residential customers following the expiration of contracts that were executed in 2000 as part of the implementation of electric deregulation in Maryland, combined with higher volumes.

Deferral under Rate Stabilization Plans

We defer the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under Senate Bill 1. During the quarter ended September 30, 2007, we deferred $4.5 million and during the nine months ended September 30, 2007, we deferred $285.4 million in electricity purchased for resale expenses. Since July 1, 2006, we have deferred $607.3 million in electricity purchased for resale expenses. These deferred expenses, plus carrying charges, are included in "Regulatory Assets (net)" in our, and BGE's, Consolidated Balance Sheets.

Recovery under Rate Stabilization Plans

In late June 2007, we began recovering previously deferred amounts from customers. We recovered $18.7 million during the quarter ended September 30, 2007 and $24.0 million during the nine months ended September 30, 2007 in deferred electricity purchased for resale expenses. As discussed in *Available Sources of Funding* section on page 50, these collections secure the payment of principal and interest and other ongoing costs associated with rate stabilization bonds issued by a subsidiary of BGE in June 2007.

Electric Operations and Maintenance Expenses

Regulated operations and maintenance expenses increased $7.4 million in the quarter ended September 30, 2007 and $16.0 million in the nine months ended September 30, 2007 compared to the same periods in 2006 mostly due to higher labor and benefit costs and the impact of inflation on other costs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $4.3 million for the nine months ended September 30, 2007 in comparison with the same period in 2006 primarily due to increased property taxes.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section of our 2006 Annual Report on Form 10-K.

Results

	Quarter Ended September 30,		**Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
		(In millions)		
Gas revenues	**$ 118.7**	$ 114.6	**$ 688.8**	$ 678.4
Gas purchased for resale expenses	**(70.6)**	(66.4)	**(457.6)**	(448.6)
Operations and maintenance expenses	**(38.1)**	(34.6)	**(114.3)**	(105.3)
Merger-related costs		(0.2)		(1.0)
Depreciation and amortization	**(11.6)**	(11.6)	**(35.3)**	(35.0)
Taxes other than income taxes	**(7.9)**	(7.4)	**(27.0)**	(24.9)
(Loss) income from operations	**$ (9.5)**	$ (5.6)	**$ 54.6**	$ 63.6

	Quarter Ended September 30,		Nine Months Ended September 30,	
Net (Loss) Income	**$ (9.8)**	$ (7.3)	**$ 18.2**	$ 26.3
Other Items Included in Operations (after-tax):				
Merger-related costs	**$**	$ (0.2)	**$**	$ (0.8)

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 16 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

The net loss from the regulated gas business increased $2.5 million during the quarter ended September 30, 2007 compared to the same period of 2006 mostly due to increased operations and maintenance expenses of $2.2 million after-tax.

Net income from the regulated gas business decreased $8.1 million during the nine months ended September 30, 2007 compared to the same period of 2006 primarily due to increased operations and maintenance expenses of $5.5 million after-tax.

Gas Revenues

The changes in gas revenues in 2007 compared to 2006 were caused by:

	Quarter Ended September 30, 2007 vs. 2006	Nine Months Ended September 30, 2007 vs. 2006
	(In millions)	
Distribution volumes	$ 0.5	$ 15.6
Revenue decoupling	(0.1)	(16.5)
Gas cost adjustments	0.1	33.1
Total change in gas revenues from gas system sales	0.5	32.2
Off-system sales	3.2	(21.3)
Other	0.4	(0.5)
Total change in gas revenues	$ 4.1	$ 10.4

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2007 compared to 2006 were:

	Quarter Ended September 30, 2007 vs. 2006	Nine Months Ended September 30, 2007 vs. 2006
Residential	(2.6)%	18.7%
Commercial	14.8	18.2
Industrial	(7.5)	(17.0)

During the quarter ended September 30, 2007 compared to the same period in 2006, we distributed less gas to residential customers due to decreased usage per customer, partially offset by an increased number of customers. We distributed more gas to commercial customers compared to the same period of 2006 mostly due to increased usage per customer and an increased number of customers. We distributed less gas to industrial customers mostly due to decreased usage per customer.

During the nine months ended September 30, 2007 compared to the same period in 2006, we distributed more gas to residential customers due to colder weather, increased usage per customer and an increased number of customers. We distributed more gas to commercial customers due to an increased number of customers and colder weather, partially offset by decreased usage per customer. We distributed less gas to industrial customers mostly due to decreased usage per customer.

Revenue Decoupling

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather patterns on our gas distribution volumes. This means our monthly gas base rate revenues are based on weather that is considered "normal" for the month and, therefore, are not affected by actual weather conditions.

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 2006 Annual Report on Form 10-K.

Gas cost adjustment revenues increased $33.1 million during the nine months ended September 30, 2007 compared to the same period of 2006 because we sold more gas, partially offset by lower prices.

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 ended September 30, 2007 compared to the same period of 2006 because we sold more gas, partially offset by lower prices.

Revenues from off-system gas sales decreased during the nine months ended September 30, 2007 compared to the same period of 2006 because we sold less gas at 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 $4.2 million during the quarter and $9.0 million during the nine months ended September 30, 2007 compared to the same periods of 2006 because we purchased more gas, partially offset by lower prices.

Gas Operations and Maintenance Expenses

Regulated operations and maintenance expenses increased $3.5 million in the quarter and $9.0 million in the nine months ended September 30, 2007 compared to the same periods in 2006 mostly due to increased maintenance requirements, higher labor and benefit costs and the impact of inflation on other costs.

Gas Taxes Other Than Income Taxes

Gas taxes other than income taxes increased $2.1 million in the nine month period ended September 30, 2007 compared to the same period in 2006 primarily due to increased property taxes.

Other Nonregulated Businesses

Results

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
		(In millions)		
Revenues	**$ 55.0**	$ 45.5	**$ 174.5**	$ 169.3
Operating expense	**(41.4)**	(31.3)	**(114.5)**	(126.6)
Merger-related costs		(0.1)		(0.3)
Depreciation and amortization	**(13.0)**	(10.6)	**(40.0)**	(28.5)
Taxes other than income taxes	**(0.6)**	(0.2)	**(1.9)**	(1.4)
Income from Operations	**$**	$ 3.3	**$ 18.1**	$ 12.5
(Loss) income from continuing operations (after-tax)	**$ (0.3)**	$ 4.1	**$ 9.9**	$ 7.9
Income from discontinued operations (after-tax)				0.9
Net (Loss) Income	**$ (0.3)**	$ 4.1	**$ 9.9**	$ 8.8
Other Items Included in Operations (after-tax):				
Merger-related costs	**$**	$	**$**	$ (0.2)

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 16 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income decreased during the quarter ended September 30, 2007 compared to the same period of 2006, mostly due to increased depreciation and amortization.

As previously discussed in our 2006 Annual Report on Form 10-K, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

Consolidated Nonoperating Income and Expenses

Gains on Sale of CEP LLC Equity

In the second and third quarters of 2007, CEP sold additional equity. As a result of these sales of equity by CEP, we recognized pre-tax gains totaling $39.2 million during the quarter ended September 30, 2007 and $52.1 million during the nine months ended September 30, 2007. We discuss the additional equity offerings in the *Notes to Consolidated Financial Statements* on page 13.

Other Income

Other income increased during the quarter and nine months ended September 30, 2007 compared to the same periods of 2006, mostly due to higher interest and investment income due to a higher cash balance.

Total other income at BGE increased during the quarter and nine months ended September 30, 2007 compared to the same periods of 2006, primarily due to carrying charges related to rate stabilization credits. We discuss the rate stabilization credits in more detail in the *Regulated Electric* section on page 43.

Fixed Charges

Fixed charges decreased during the quarter and nine months ended September 30, 2007 compared to the same periods of 2006, mostly due to a lower level of debt outstanding.

Fixed charges at BGE increased during the quarter and nine months ended September 30, 2007 compared to the same periods of 2006 mostly due to interest expense recognized on debt that was issued in October 2006 and the rate stabilization bonds issued during the second quarter of 2007.

Income Taxes

Our income taxes increased $13.1 million during the quarter ended September 30, 2007 compared to the same period of 2006 mostly because of a $31.3 million decrease in synthetic fuel tax credits partially offset by a decrease in taxable income. We discuss synthetic fuel tax credits in more detail in the *Notes to Consolidated Financial Statements* on page 18.

Our income taxes increased $27.8 million during the nine months ended September 30, 2007 compared to the same period of 2006 mostly because of an increase in pre-tax income. This was partially offset by an increase in synthetic fuel tax credits of $8.4 million.

Income taxes at BGE decreased during the quarter and nine months ended September 30, 2007 compared to the same periods of 2006 primarily due to a decrease in pre-tax income.

Financial Condition

Cash Flows

The following table summarizes our cash flows for 2007 and 2006, excluding the impact of changes in intercompany balances.

	2007 Segment Cash Flows			Consolidated Cash Flows	
	Nine Months Ended September 30, 2007			Nine Months Ended September 30,	
	Merchant	Regulated	Other	2007	2006
	(In millions)				
Operating Activities					
Net income	$ 449.4	$ 104.1	$ 9.9	$ 563.4	$ 531.5
Non-cash adjustments to net income	213.5	18.2	17.0	248.7	370.6
Changes in working capital	(59.9)	(101.0)	18.9	(142.0)	(762.5)
Defined benefit obligations*				(48.0)	33.1
Other	(9.6)	(25.5)	29.7	(5.4)	(9.6)
Net cash provided by (used in) operating activities	593.4	(4.2)	75.5	616.7	163.1
Investing Activities					
Investments in property, plant and equipment	(612.3)	(264.1)	(43.9)	(920.3)	(668.0)
Acquisitions, net of cash acquired	(344.1)			(344.1)	(133.5)
Contributions to nuclear decommissioning trust funds	(8.8)			(8.8)	(8.8)
Sales of investments and other assets	4.0		1.6	5.6	43.5
Contract and portfolio acquisitions	(474.2)			(474.2)	(2.3)
Issuances of loans receivable	(19.0)			(19.0)	(65.4)
Other	(43.0)	(21.1)	(1.3)	(65.4)	33.8
Net cash used in investing activities	(1,497.4)	(285.2)	(43.6)	(1,826.2)	(800.7)
Cash flows from operating activities less cash flows from investing activities	$ (904.0)	$ (289.4)	$ 31.9	(1,209.5)	(637.6)
Financing Activities*					
Net (repayment) issuance of debt				(93.0)	20.5
Proceeds from issuance of common stock				47.7	56.2
Common stock dividends paid				(226.8)	(195.7)
Reacquisition of common stock				(114.4)	
Proceeds from contract and portfolio acquisitions				847.8	221.3
Other				10.8	43.0
Net cash provided by financing activities				472.1	145.3
Net Decrease in Cash and Cash Equivalents				$ (737.4)	$ (492.3)

**Items are not allocated to the business segments because they are managed for the company as a whole.*
Certain prior-period amounts have been reclassified to conform to the current period presentation.

Cash Flows from Operating Activities

Cash provided by operating activities was $616.7 million in 2007 compared to $163.1 million in 2006. This $453.6 million increase was primarily due to favorable changes in working capital, offset in part by a decrease in non-cash adjustments to net income in 2007.

Changes in working capital had a negative impact of $142.0 million on cash flow from operations in 2007 compared to a negative impact of $762.5 million in 2006. The net increase of $620.5 million was primarily due to cash changes related to our collateral positions, which is impacted by commodity price volatility and the level of risk management and trading activities. During the nine months ended September 30, 2007, we received approximately $110 million in cash due to a decrease in collateral requirements, compared to the same period of 2006, when we posted cash collateral of approximately $627 million.

Non-cash adjustments to net income decreased $121.9 million in 2007 compared to 2006 primarily due to a change in deferred fuel costs of $84.0 million related mostly to higher deferrals of electricity purchased for resale under the BGE rate stabilization plan. We discuss the rate stabilization plan in more detail in the *Item 1.-Business-Electric Regulatory Matters and Competition* section of our 2006 Annual Report on Form 10-K.

Cash Flows from Investing Activities

Cash used in investing activities was $1,826.2 million in 2007 compared to $800.7 million in 2006. The $1,025.5 million increase in cash used in 2007 compared to 2006 was primarily due to the following:

- a $471.9 million increase in contract and portfolio acquisitions that we discuss in more detail below,
- a $252.3 million increase in investments in property, plant and equipment, which includes spending related to environmental controls at our generating facilities, and
- a $210.6 million increase in acquisitions, primarily related to our acquisitions of working interests in gas and oil producing properties and Cornerstone Energy as discussed in more detail in the *Notes to Consolidated Financial Statements* beginning on page 13.

Cash Flows from Financing Activities

Cash provided by financing activities was $472.1 million in 2007 compared to $145.3 million in 2006. The increase of $326.8 million was primarily due to an increase in gross proceeds from contract and portfolio acquisitions of $626.5 million, which we discuss below. This was partially offset by cash used for reacquisition of common stock of $114.4 million, a net decrease in cash related to changes in short-term borrowings and long-term debt of $113.5 million, and a $31.1 million increase in our dividends paid in 2007 compared to 2006.

In October 2007, our board of directors approved a common share repurchase program for up to $1 billion of our outstanding common shares. Subsequent to this approval, on October 31, 2007, we entered into an accelerated share repurchase agreement with a financial institution, and on November 2, 2007 we purchased 2,023,527 of outstanding shares of our common stock for $250 million. We discuss the share repurchase program in more detail in the *Notes to Consolidated Financial Statements* on page 15.

Contract and Portfolio Acquisitions

During 2007 and 2006 our merchant energy business acquired pre-existing power-related agreements, which generated significant cash flows at the inception of the agreements. These agreements had contract prices that differed from market prices at closing, which resulted in cash payments from the counterparty at the acquisition of the contracts.

We received net cash of $373.6 million during the nine months ended September 30, 2007 and $219.0 million during the same period of 2006 for various contract and portfolio acquisitions. We reflect the underlying contracts on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether they were in-the-money or out-of-the-money at closing; therefore, we have also reflected them on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Nine Months Ended September 30,	**2007**	**2006**
	(In millions)	
Financing activities proceeds from contract and portfolio acquisitions	**$ 847.8**	$ 221.3
Investing activities contract and portfolio acquisitions	**(474.2)**	(2.3)
Cash flows from contract and portfolio acquisitions	**$ 373.6**	$ 219.0

We record the proceeds we receive to acquire energy purchase and sale agreements as a financing cash inflow because it constitutes a prepayment for a portion of the market price of energy, which we will buy or sell over the term of the agreements and does not represent a cash inflow from current period operating activities. For those acquired contracts that are derivatives, we record the ongoing cash flows related to the contract with the counterparties as financing cash flows in accordance with SFAS No. 149, *Amendment of Statement 133 on Derivative*

Instruments and Hedging Activities. For those acquired contracts that are not derivatives, we record the ongoing cash flows related to the contract as operating cash flows.

Security Ratings

In June 2007, in connection with BondCo's issuance of rate stabilization bonds, the rating agencies took the following actions:

- Standard and Poor's Rating Group and Fitch Ratings issued AAA ratings for the bonds, and
- Moody's Investors Service issued an Aaa rating for the bonds.

We discuss the issuance of the rate stabilization bonds in more detail in the section on the next page.

Available Sources of Funding

We continuously monitor our liquidity requirements and believe that our facilities and access to the capital markets provide sufficient liquidity to meet our business requirements. We discuss our available sources of funding in more detail below.

Constellation Energy

Constellation Energy had committed bank lines of credit under credit facilities of $4.05 billion at September 30, 2007 for short-term financial needs. At September 30, 2007, these facilities can issue letters of credit up to approximately $4.05 billion. Letters of credit issued under all of our facilities totaled $1.9 billion at September 30, 2007.

In July 2007, we entered into a new five-year credit facility totaling $3.85 billion. This new facility amended and restated three facilities totaling $3.35 billion a $1.5 billion facility that would have expired in March 2010, a $1.1 billion facility that would have expired in November 2010, and a $750 million facility that would have expired in November 2010. In connection with entering into the new five-year credit facility, we terminated a $1.0 billion facility that would have expired in October 2007.

In connection with the acquisition of coalbed methane properties and the related April 2007 equity issuance discussed on page 13, we deconsolidated CEP and began accounting for our investment using the equity method of accounting under APB No. 18. As a result, the $32.0 million of borrowings outstanding under the CEP credit facility at the time of deconsolidation are no longer included in our Consolidated Balance Sheets.

In July 2007, we announced a joint venture, UniStar Nuclear Energy, LLC (UniStar) with an affiliate of Electricite de France (EDF). The agreement with EDF includes a phased-in investment of $625 million by EDF in UniStar. We discuss this joint venture in more detail in the *Notes to Consolidated Financial Statements* on page 15.

BGE

BGE currently maintains a $400.0 million five-year revolving credit facility expiring in 2011. BGE can borrow directly from the banks, use the facilities to allow commercial paper to be issued, or issue letters of credit. As of September 30, 2007, BGE had $0.7 million in letters of credit issued, which results in $399.3 million in unused credit facilities.

In June 2007, BondCo, a subsidiary of BGE, issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover deferred power purchase costs. We discuss BondCo in more detail in the *Notes to Consolidated Financial Statements* on page 11. Below are the details of the rate stabilization bonds:

Principal	**Interest Rate**	**Scheduled Maturity Date**
$284.0	5.47%	October 2012
220.0	5.72	April 2016
119.2	5.82	April 2017

The bonds are secured primarily by a usage-based, non-bypassable charge payable by all of BGE's residential electric customers over the next ten years. The charges will be adjusted semi-annually to ensure that the aggregate charges collected are sufficient to pay principal and interest on the bonds as well as certain on-going costs of administering and servicing the bonds. BondCo cannot use the charges collected to satisfy any other obligations. BondCo's assets are not assets of any affiliate and are not available to pay creditors of any affiliate of BondCo. If BondCo is unable to make principal and interest payments on the bonds, neither Constellation Energy nor BGE are required to make the payments on behalf of BondCo.

Capital Resources

Our estimated annual capital requirements for the years 2007 and 2008 are shown in the table on the next page.

We will continue to have cash requirements for:

- working capital needs,

- payments of interest, distributions, and dividends,
- capital expenditures, and
- the retirement of debt and redemption of preference stock.

Capital requirements for 2007 and 2008 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 on the next page 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 market conditions on those projects,
- the cost and availability of capital,
- 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 57 and *Item 1A. Risk Factors* section on page 56. We discuss the potential impact of environmental legislation and regulation in more detail in *Business Environment* section beginning on page 26 and *Item 1. Business Environmental Matters* section of our 2006 Annual Report on Form 10-K.

Calendar Year Estimates	**2007**	**2008**
	(In millions)	
Nonregulated Capital Requirements:		
Merchant energy		
Generation plants	$ 195	$ 375
Nuclear fuel	150	210
Environmental controls	170	540
Portfolio acquisitions/investments	550	195
Technology/other	190	110
Total merchant energy capital requirements	1,255	1,430
Other nonregulated capital requirements	25	10
Total nonregulated capital requirements	1,280	1,440
Regulated Capital Requirements:		
Regulated electric	370	445
Regulated gas	60	80
Total regulated capital requirements	430	525
Total capital requirements	$ 1,710	$ 1,965

Capital Requirements

Merchant Energy Business

Our merchant energy business' capital requirements consist of its continuing requirements, including expenditures for:

improvements to generating plants,

nuclear fuel costs,

upstream gas investments,

portfolio acquisitions and other investments,

costs of complying with the EPA, Maryland, and Pennsylvania environmental regulations and legislation, and

enhancements to our information technology infrastructure.

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.

Funding for Capital Requirements

We discuss our funding for capital requirements in our 2006 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 the growth in our merchant energy 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 September 30, 2007 in the following table:

	Payments				
	2007	2008-2009	2010-2011	There-after	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 5.1	$ 507.8	$ 50.7	$ 2,214.4	$ 2,778.0
Interest	43.7	327.0	277.1	1,272.0	1,919.8
Total	48.8	834.8	327.8	3,486.4	4,697.8
BGE					
Principal		415.0	138.3	1,661.8	2,215.1
Interest	24.3	239.1	208.8	1,480.0	1,952.2
Total	24.3	654.1	347.1	3,141.8	4,167.3
BGE preference stock				190.0	190.0
Operating leases[2]	125.8	659.1	400.5	829.6	2,015.0
Purchase obligations:[3]					
Purchased capacity and energy[4]	91.8	744.3	268.6	374.0	1,478.7
Fuel and transportation	1,125.6	2,674.5	812.3	1,166.5	5,778.9
Other	186.8	93.7	7.8	28.1	316.4
Other noncurrent liabilities:					
Pension benefits[5]	2.0	74.7	134.3	65.3	276.3
Postretirement and postemployment benefits[6]	8.3	90.5	108.5	305.7	513.0
Total contractual payment obligations	$ 1,613.4	$ 5,825.7	$ 2,406.9	$ 9,587.4	$ 19,433.4

1

Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $274.8 million early through put options and remarketing features. Interest on variable rate debt is included based on the September 30, 2007 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 2006 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

Amounts related to pension benefits reflect our current 5-year forecast of contributions for our qualified pension plans and participant payments for our nonqualified pension plans. Refer to Note 7 of our 2006 Annual Report on Form 10-K for more detail on our pension plans.

6

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.

Liquidity Provisions

In many cases, customers of our wholesale marketing, risk management, and trading operation rely on the creditworthiness of Constellation Energy. A decline below investment grade by Constellation Energy would negatively impact the business prospects of that operation.

We regularly review our liquidity needs to ensure that we have adequate facilities available to meet collateral requirements. This includes having liquidity available to meet margin requirements for our competitive supply operations.

We have certain agreements that contain provisions that would require additional collateral upon significant credit rating decreases in senior unsecured debt of Constellation Energy. Decreases in Constellation Energy's credit ratings would not trigger an early payment on any of our credit facilities.

Under counterparty contracts related to our wholesale marketing, risk management, and trading operation, we are obligated to post collateral if Constellation Energy's senior unsecured credit ratings declined below established contractual levels. Based on contractual provisions at September 30, 2007, we estimate that if Constellation Energy's senior unsecured debt were downgraded we would have the following additional collateral obligations:

Credit Ratings Downgraded to	Level Below Current Rating	Incremental Obligations	Cumulative Obligations
		(In millions)	
BBB/Baa2	1	$ 106	$ 106
BBB-/Baa3	2	228	334
Below investment grade	3	634	968

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, which could be material. We discuss our credit ratings in the *Security Ratings* section of our 2006 Annual Report on Form 10-K and our credit facilities in the *Available Sources of Funding* section on page 50.

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 September 30, 2007, the debt to capitalization ratio as defined in the credit agreements was 45%. The failure by Constellation Energy to comply with these provisions could result in the acceleration of the maturity of the debt outstanding under these facilities, which is primarily letters of credit issued in support of our competitive supply operations. We detail our letters of credit in the *Available Sources of Funding* section on page 50.

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 September 30, 2007, the debt to capitalization ratio for BGE as defined in these credit agreements was 45%.

Off-Balance Sheet Arrangements

We discuss our off-balance sheet arrangements in our 2006 Annual Report on Form 10-K.

At September 30, 2007, Constellation Energy had a total of $13,932.0 million in guarantees outstanding, of which $12,737.3 million related to our competitive supply activities. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. While the stated limit of these guarantees is $12,737.3 million, our calculated fair value of obligations for commercial transactions covered by these guarantees was $3,133.1 million at September 30, 2007. The $3,133.1 million represents the total amount Constellation Energy could be required to fund based on market prices as of September 30, 2007, if the subsidiaries do not honor contractual commitments covered by these guarantees. For those guarantees related to our mark-to-market energy or risk management 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* on page 19.

Market Risk

Commodity Risk

We measure the sensitivity of our wholesale marketing, risk management, and trading mark-to-market energy contracts to potential changes in market prices using value at risk. Value at risk represents the potential pre-tax loss in the fair value of our wholesale marketing, risk management, and trading mark-to-market energy assets and liabilities over one and ten-day holding periods. We discuss value at risk in more detail in the *Market Risk* section of our 2006 Annual Report on Form 10-K.

The table on the next page is the value at risk associated with our wholesale marketing, risk management, and trading operation's mark-to-market energy assets and liabilities, including both trading and non-trading activities.

We discuss our mark-to-market results in more detail in the *Competitive Supply* section beginning on page 34.

		Quarter Ended September 30, 2007
		(In millions)
99% Confidence Level, One-Day Holding Period		
Average	$	19.3
High		26.8
95% Confidence Level, One-Day Holding Period		
Average		14.7
High		20.4
95% Confidence Level, Ten-Day Holding Period		
Average		46.5
High		64.6

The following table details our value at risk for the trading portion of our wholesale marketing, risk management, and trading mark-to-market energy assets and liabilities over a one-day holding period at a 99% confidence level for the third quarter of 2007:

		Quarter Ended September 30, 2007
		(In millions)
Average	$	12.7
High		15.8

Due to the inherent limitations of statistical measures such as value at risk and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method. As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Wholesale Credit Risk

We actively monitor the credit portfolio of our wholesale marketing, risk management, and trading operation to attempt to reduce the impact of counterparty default. As of September 30, 2007 and December 31, 2006, the credit portfolio of our wholesale marketing, risk management, and trading operation had the following public credit ratings:

	September 30, 2007	December 31, 2006
Rating		
Investment Grade[1]	**46%**	61%
Non-Investment Grade	**8**	3
Not Rated	**46**	36

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.

We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. The "Not Rated" category in the table above includes counterparties that do not have public credit ratings and include governmental entities, municipalities, cooperatives, power pools, and other load-serving entities, and marketers for which we determine creditworthiness based on internal credit ratings.

The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

	September 30, 2007	December 31, 2006
Investment Grade Equivalent	**66%**	82%
Non-Investment Grade	**34**	18

The credit quality of our wholesale credit portfolio declined during the first nine months of 2007 as a result of the downgrade of Illinois utilities resulting from political and regulatory issues surrounding rate increases and our growing exposure to international freight and coal counterparties.

A portion of our wholesale credit risk is related to transactions that are recorded in our Consolidated Balance Sheets. These transactions primarily consist of open positions from our wholesale marketing, risk management, and trading operation that are accounted for using mark-to-market accounting, as well as amounts owed by wholesale counterparties for transactions that settled but have not yet been paid. The table on the next page highlights the credit quality and exposures related to these activities at September 30, 2007:

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
			(Dollars in millions)		
Investment grade	$ 1,376	$ 291	$ 1,085		$
Split rating	52		52		
Non-investment grade	75	30	45		
Internally rated investment grade	315	36	279		
Internally rated non-investment grade	236	15	221		
Total	$ 2,054	$ 372	$ 1,682		$

Due to the possibility of extreme 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 electricity our wholesale marketing, risk management, and trading operation had contracted for), we could incur a loss that could have a material impact on our financial results.

Additionally, if a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and additional payments, if any, we would have to make to settle unrealized losses on accrual contracts.

We continue to examine plans to achieve our strategies and to further strengthen our balance sheet and enhance our liquidity. We discuss our liquidity in the *Financial Condition* section on page 52.

Interest Rate Risk, Retail Credit Risk, Foreign Currency Risk, and Equity Price Risk

We discuss our exposure to interest rate risk, retail credit risk, foreign currency risk, and equity price risk in the *Market Risk* section of our 2006 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:

- SFAS No. 133 hedging activities in the *Notes to Consolidated Financial Statements* beginning on page 22,
- activities of our wholesale marketing, risk management, and trading operation in the *Merchant Energy Business* section of *Management's Discussion and Analysis* beginning on page 31,
- evaluation of commodity and credit risk in the *Market Risk* section of *Management's Discussion and Analysis* beginning on page 52, and
- changes to our business environment in the *Business Environment* section of *Management's Discussion and Analysis* beginning on page 26.

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 officers and principal financial officer of both Constellation Energy and BGE have 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 and BGE's disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2007, 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.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We discuss our Legal Proceedings in the *Notes to Consolidated Financial Statements* beginning on page 21.

Item 1A. Risk Factors

The risk factors included in our 2006 Annual Report on Form 10-K have not materially changed. You should consider carefully the risks described under *Item 1A. Risk Factors* in our 2006 Annual Report on Form 10-K. The risks and uncertainties described in our 2006 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 events described actually occur, our business and financial results could be materially adversely affected.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock. There were no shares repurchased by us in the open market to satisfy employee stock option exercises and restricted stock grants during the third quarter of 2007.

Period	Total Number of Shares Purchased	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans and Programs
July 1 July 31, 2007		$		
August 1 August 31, 2007	406	78.49		
September 1 September 30, 2007	794	89.05		
Total	1,200	$ 85.47		

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,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,
- the timing and extent of deregulation of, and competition in, the energy markets, and the rules and regulations adopted in those markets,
- uncertainties associated with estimating natural gas reserves, developing properties, and extracting natural gas,
- regulatory or legislative developments that affect deregulation, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,
- the ability of our regulated and nonregulated businesses to comply with complex and/or changing market rules and regulations,
- the inability of BGE to recover all its costs associated with providing customers service,
- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and BGE's 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,
- operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic 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, liabilities associated with catastrophic events, and other events beyond our control,
- the actual outcome of uncertainties associated with assumptions and estimates using judgment when 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,
- 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 and complete acquisitions and sales of businesses and assets, and

cost and other effects of legal and administrative proceedings that may not be covered by insurance, including environmental liabilities.

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 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 assume responsibility to update these forward looking statements.

Item 6. Exhibits

Exhibit No. 10(a)	Letter Agreement, dated October 31, 2007, by and between Constellation Energy Group, Inc. and J.P. Morgan Securities Inc., as agent for JPMorgan Chase Bank, National Associates, London Branch (Designated as Exhibit 10.1 to the Current Report on Form 8-K dated November 1, 2007, File No. 1-12869).
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 Executive Vice President, Chief Financial Officer, and Chief Risk 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 Senior Vice President and Chief Financial Officer 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 Executive Vice President, Chief Financial Officer, and Chief Risk 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 Senior Vice President and Chief Financial 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.

* Incorporated by reference

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)

BALTIMORE GAS AND ELECTRIC COMPANY

(Registrant)

Date: November 8, 2007

/s/ JOHN R. COLLINS

John R. Collins,
Executive Vice President of Constellation Energy Group, Inc. and Senior Vice President of Baltimore Gas and Electric Company, and as Principal Financial Officer of each Registrant