CONSTELLATION ENERGY GROUP INC
Form 10-Q
August 08, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For The Quarterly Period Ended **June 30, 2005**

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 an accelerated filer Yes ý No o

Indicate by check mark whether Baltimore Gas and Electric Company is an accelerated filer Yes o No ý

Common Stock, without par value 177,978,341 shares outstanding of Constellation Energy Group, Inc. on July 29, 2005.

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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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended June 30, 2005	2004	*Six Months Ended June 30,* 2005	2004
	(In millions, except per share amounts)			
Revenues				
Nonregulated revenues	**$ 2,942.0**	$ 2,198.6	**$ 5,715.7**	$ 4,425.8
Regulated electric revenues	**465.1**	477.2	**956.6**	961.6
Regulated gas revenues	**141.7**	111.5	**506.3**	429.4
Total revenues	**3,548.8**	2,787.3	**7,178.6**	5,816.8
Expenses				
Fuel and purchased energy expenses	**2,638.0**	1,927.7	**5,354.4**	4,128.6
Operating expenses	**473.6**	466.4	**938.9**	866.0
Depreciation and amortization	**136.5**	127.3	**270.2**	248.9
Accretion of asset retirement obligations	**15.3**	12.4	**30.4**	23.5
Taxes other than income taxes	**67.1**	61.6	**135.6**	125.6
Total expenses	**3,330.5**	2,595.4	**6,729.5**	5,392.6
Income from Operations	**218.3**	191.9	**449.1**	424.2
Other Income	**11.3**	5.0	**21.6**	9.6
Fixed Charges				
Interest expense	**76.7**	83.5	**158.0**	168.3
Interest capitalized and allowance for borrowed funds used during construction	**(2.6)**	(3.2)	**(5.6)**	(5.8)
BGE preference stock dividends	**3.3**	3.3	**6.6**	6.6
Total fixed charges	**77.4**	83.6	**159.0**	169.1
Income from Continuing Operations Before Income Taxes	**152.2**	113.3	**311.7**	264.7
Income Tax Expense (Benefit)	**33.2**	(14.9)	**72.4**	26.2
Income from Continuing Operations	**119.0**	128.2	**239.3**	238.5
Income from discontinued operations related to Oleander, net of income taxes of \$1.8, \$1.7, \$2.1, and \$3.1, respectively	**2.7**	2.7	**3.1**	4.9
Loss from discontinued operations related to Hawaiian Geothermal Facility, net of income taxes of \$2.6 and \$26.4, respectively		(2.7)		(49.0)
Net Income	**$ 121.7**	$ 128.2	**$ 242.4**	$ 194.4
Earnings Applicable to Common Stock	**$ 121.7**	$ 128.2	**$ 242.4**	$ 194.4
Average Shares of Common Stock Outstanding Basic	**177.6**	168.7	**177.2**	168.4

	Three Months Ended June 30,		Six Months Ended June 30,	
Average Shares of Common Stock Outstanding Diluted	**179.7**	169.6	**179.2**	169.4
Earnings Per Common Share from Continuing Operations Basic	**$ 0.67**	$ 0.76	**$ 1.35**	$ 1.42
Income from discontinued operations related to Oleander	**0.02**	0.02	**0.02**	0.03
Loss from discontinued operations related to Hawaiian Geothermal Facility		(0.02)		(0.30)
Earnings Per Common Share Basic	**$ 0.69**	$ 0.76	**$ 1.37**	$ 1.15
Earnings Per Common Share from Continuing Operations Diluted	**$ 0.66**	$ 0.76	**$ 1.33**	$ 1.41
Income from discontinued operations related to Oleander	**0.02**	0.01	**0.02**	0.03
Loss from discontinued operations related to Hawaiian Geothermal Facility		(0.01)		(0.29)
Earnings Per Common Share Diluted	**$ 0.68**	$ 0.76	**$ 1.35**	$ 1.15
Dividends Declared Per Common Share	**$ 0.335**	$ 0.285	**$ 0.670**	$ 0.570

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In millions)		
Net Income	**$ 121.7**	$ 128.2	**$ 242.4**	$ 194.4
Other comprehensive income (OCI)				
Reclassification of net gains on sales of securities from OCI to net income, net of taxes	**(0.1)**		**(0.1)**	(0.3)
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes	**(60.5)**	(44.4)	**(98.2)**	(69.2)
Net unrealized (losses) gains on hedging instruments, net of taxes	**(132.3)**	102.5	**86.2**	198.8
Net unrealized (losses) gains on securities, net of taxes	**(2.3)**	(12.9)	**8.6**	14.0
Net unrealized gain on foreign currency, net of taxes	**0.4**		**0.3**	
Comprehensive (Loss) Income	**$ (73.1)**	$ 173.4	**$ 239.2**	$ 337.7

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

	June 30,* 2005	***December 31,* 2004**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 724.6**	$ 706.3
Accounts receivable (net of allowance for uncollectibles of **$43.7** and $43.1, respectively)	**2,191.7**	1,979.3
Mark-to-market energy assets	**626.1**	567.3
Risk management assets	**589.8**	471.5
Fuel stocks	**324.0**	298.3
Materials and supplies	**205.5**	203.8
Other	**287.9**	262.9
Total current assets	**4,949.6**	4,489.4
Investments and Other Assets		
Nuclear decommissioning trust funds	**1,065.9**	1,033.7
Investments in qualifying facilities and power projects	**310.6**	318.4
Mark-to-market energy assets	**626.2**	359.8
Risk management assets	**478.3**	306.2
Regulatory assets (net)	**145.7**	195.4
Goodwill	**147.1**	144.8
Other	**523.7**	412.8
Total investments and other assets	**3,297.5**	2,771.1
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**8,718.0**	8,638.4
Regulated property, plant and equipment	**5,450.8**	5,412.7
Nuclear fuel (net of amortization)	**258.3**	264.3
Accumulated depreciation	**(4,290.4)**	(4,228.8)
Net property, plant and equipment	**10,136.7**	10,086.6
Total Assets	**$ 18,383.8**	$ 17,347.1

** Unaudited*

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	June 30, **2005***	*December 31,* **2004**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 1.6**	$
Current portion of long-term debt	**193.7**	480.4
Accounts payable and accrued liabilities	**1,583.2**	1,424.9
Customer deposits and collateral	**325.7**	223.8
Mark-to-market energy liabilities	**609.1**	559.7
Risk management liabilities	**272.2**	304.3
Accrued expenses and other	**605.1**	669.3
Total current liabilities	**3,590.6**	3,662.4
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,251.7**	1,303.3
Asset retirement obligations	**863.3**	825.0
Mark-to-market energy liabilities	**550.6**	315.0
Risk management liabilities	**1,148.2**	472.2
Postretirement and postemployment benefits	**377.8**	375.3
Net pension liability	**244.0**	269.7
Deferred investment tax credits	**67.6**	71.2
Other	**296.7**	232.0
Total deferred credits and other liabilities	**4,799.9**	3,863.7
Long-term Debt		
Long-term debt of Constellation Energy	**3,070.6**	3,363.3
Long-term debt of nonregulated businesses	**444.1**	437.2
First refunding mortgage bonds of BGE	**346.3**	346.3
Other long-term debt of BGE	**879.6**	899.6
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	**(9.1)**	(10.5)
Current portion of long-term debt	**(193.7)**	(480.4)
Total long-term debt	**4,795.5**	4,813.2
Minority Interests	**95.4**	90.9
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock	**2,567.9**	2,502.5
Retained earnings	**2,549.2**	2,425.9

	June 30, 2005*	December 31, 2004
Accumulated other comprehensive loss	**(204.7)**	(201.5)
Total common shareholders' equity	**4,912.4**	4,726.9
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 18,383.8**	$ 17,347.1

** Unaudited*

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Six Months Ended June 30,	2005	2004
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 242.4**	$ 194.4
Adjustments to reconcile to net cash provided by operating activities		
(Income) loss from discontinued operations	**(3.1)**	44.1
Depreciation and amortization	**317.9**	315.2
Accretion of asset retirement obligations	**30.4**	23.5
Deferred income taxes	**8.5**	53.7
Investment tax credit adjustments	**(3.6)**	(3.6)
Deferred fuel costs	**12.8**	10.9
Pension and postemployment benefits	**(21.5)**	(22.4)
Net gain on sales of investments and other assets	**(4.0)**	(5.9)
Impairment losses and other costs	**0.3**	2.6
Equity in earnings of affiliates less than dividends received	**21.6**	18.2
Revenues from derivative contracts classified as financing activities under SFAS No. 149	**(22.8)**	
Changes in		
Accounts receivable	**(138.3)**	392.4
Mark-to-market energy assets and liabilities	**(40.9)**	35.8
Risk management assets and liabilities	**(49.3)**	(0.6)
Materials, supplies, and fuel stocks	**(85.2)**	(36.6)
Other current assets	**12.5**	61.1
Accounts payable and accrued liabilities	**165.1**	(459.0)
Other current liabilities	**30.2**	58.2
Other	**5.8**	(20.7)
Net cash provided by operating activities	**478.8**	661.3
Cash Flows From Investing Activities		
Investments in property, plant and equipment	**(303.7)**	(322.0)
Asset acquisitions and business combinations, net of cash acquired	**(237.9)**	(430.0)
Contributions to nuclear decommissioning trust funds	**(8.8)**	(13.2)
Proceeds from sale of discontinued operations	**217.6**	72.7
Sales of investments and other assets	**1.1**	14.1
Issuances of loans receivable	**(82.8)**	
Other investments	**(26.0)**	(10.1)
Net cash used in investing activities	**(440.5)**	(688.5)
Cash Flows From Financing Activities		
Net issuance (maturity) of short-term borrowings	**1.6**	(5.1)
Proceeds from issuance of common stock	**45.2**	30.5
Repayment of long-term debt	**(327.9)**	(172.4)
Common stock dividends paid	**(109.6)**	(91.4)
Proceeds from acquired contracts	**381.5**	
Revenues from derivative contracts classified as financing activities under SFAS No. 149	**22.8**	
Other	**(33.6)**	1.3

Six Months Ended June 30,	2005	2004
Net cash used in financing activities	**(20.0)**	(237.1)
Net Increase (Decrease) in Cash and Cash Equivalents	**18.3**	(264.3)
Cash and Cash Equivalents at Beginning of Period	**706.3**	721.3
Cash and Cash Equivalents at End of Period	**$ 724.6**	$ 457.0

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 June 30, 2005	*Three Months Ended June 30,* 2004	*Six Months Ended June 30,* 2005	*Six Months Ended June 30,* 2004
		(In millions)		
Revenues				
Electric revenues	**$ 465.1**	$ 477.2	**$ 956.6**	$ 961.6
Gas revenues	**145.2**	112.6	**511.0**	432.1
Total revenues	**610.3**	589.8	**1,467.6**	1,393.7
Expenses				
Operating expenses				
Electricity purchased for resale	**244.4**	254.3	**486.5**	494.7
Gas purchased for resale	**90.1**	59.5	**350.4**	275.5
Operations and maintenance	**112.0**	109.2	**219.8**	204.4
Depreciation and amortization	**58.4**	60.7	**118.0**	120.6
Taxes other than income taxes	**41.0**	40.5	**84.8**	83.1
Total expenses	**545.9**	524.2	**1,259.5**	1,178.3
Income from Operations	**64.4**	65.6	**208.1**	215.4
Other Income	**2.5**		**3.5**	1.0
Fixed Charges				
Interest expense	**23.8**	24.3	**47.5**	49.7
Allowance for borrowed funds used during construction	**(0.6)**	(0.2)	**(1.0)**	(0.5)
Total fixed charges	**23.2**	24.1	**46.5**	49.2
Income Before Income Taxes	**43.7**	41.5	**165.1**	167.2
Income Taxes	**16.8**	16.3	**63.9**	66.0
Net Income	**26.9**	25.2	**101.2**	101.2
Preference Stock Dividends	**3.3**	3.3	**6.6**	6.6
Earnings Applicable to Common Stock	**$ 23.6**	$ 21.9	**$ 94.6**	$ 94.6

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended June 30, 2005	*Three Months Ended June 30,* 2004	*Six Months Ended June 30,* 2005	*Six Months Ended June 30,* 2004
		(In millions)		

	Three Months Ended June 30,		Six Months Ended June 30,	
Net Income	**$ 23.6**	$ 21.9	**$ 94.6**	$ 94.6
Other comprehensive income				
Reclassification of unrealized gain on hedging instruments from OCI to net income, net of taxes		(0.1)		(0.1)
Comprehensive Income	**$ 23.6**	$ 21.8	**$ 94.6**	$ 94.5

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	June 30, 2005*	***December 31, 2004***
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 10.4**	$ 8.2
Accounts receivable (net of allowance for uncollectibles of **$13.0** and $13.0, respectively)	**325.0**	381.8
Investment in cash pool, affiliated company	**317.3**	127.9
Accounts receivable, affiliated companies	**2.4**	1.0
Fuel stocks	**57.4**	86.5
Materials and supplies	**36.8**	34.6
Prepaid taxes other than income taxes	**0.2**	44.5
Other	**29.7**	7.2
Total current assets	**779.2**	691.7
Investments and Other Assets		
Regulatory assets (net)	**145.7**	195.4
Receivable, affiliated company	**165.7**	150.4
Other	**144.5**	134.2
Total investments and other assets	**455.9**	480.0
Utility Plant		
Plant in service		
Electric	**3,823.7**	3,759.3
Gas	**1,101.2**	1,086.7
Common	**423.0**	478.4
Total plant in service	**5,347.9**	5,324.4
Accumulated depreciation	**(1,915.9)**	(1,921.5)
Net plant in service	**3,432.0**	3,402.9
Construction work in progress	**99.7**	83.1
Plant held for future use	**3.2**	5.2
Net utility plant	**3,534.9**	3,491.2
Total Assets	**$ 4,770.0**	$ 4,662.9

** Unaudited*

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	June 30, 2005*	*December 31,* 2004
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	$ **170.9**	$ 165.9
Accounts payable and accrued liabilities	**116.6**	125.4
Accounts payable and accrued liabilities, affiliated companies	**227.7**	146.1
Customer deposits	**64.8**	64.3
Accrued taxes	**17.2**	32.2
Accrued expenses and other	**62.2**	71.7
Total current liabilities	**659.4**	605.6
Deferred Credits and Other Liabilities		
Deferred income taxes	**590.1**	608.0
Postretirement and postemployment benefits	**277.3**	278.2
Deferred investment tax credits	**16.0**	16.9
Other	**23.2**	20.0
Total deferred credits and other liabilities	**906.6**	923.1
Long-term Debt		
First refunding mortgage bonds of BGE	**346.3**	346.3
Other long-term debt of BGE	**879.6**	899.6
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	**(2.8)**	(3.2)
Current portion of long-term debt	**(170.9)**	(165.9)
Total long-term debt	**1,334.9**	1,359.5
Minority Interest	**18.5**	18.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**747.7**	653.1
Accumulated other comprehensive income	**0.7**	0.7
Total common shareholder's equity	**1,660.6**	1,566.0

	June 30, 2005*	December 31, 2004
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 4,770.0**	$ 4,662.9

** Unaudited*

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Six Months Ended June 30,	**2005**	2004
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 101.2**	$ 101.2
Adjustments to reconcile to net cash provided by operating activities Depreciation and amortization	**125.3**	122.2
Deferred income taxes	**(18.0)**	10.7
Investment tax credit adjustments	**(0.9)**	(0.9)
Deferred fuel costs	**12.8**	10.9
Pension and postemployment benefits	**(14.5)**	(24.1)
Allowance for equity funds used during construction	**(1.8)**	(0.9)
Changes in		
Accounts receivable	**56.8**	27.4
Receivables, affiliated companies	**(1.4)**	3.0
Materials, supplies, and fuel stocks	**26.9**	(2.4)
Other current assets	**21.8**	22.2
Accounts payable and accrued liabilities	**(8.8)**	(32.6)
Accounts payable and accrued liabilities, affiliated companies	**81.6**	165.6
Other current liabilities	**(24.0)**	(36.7)
Other	**1.7**	(7.6)
Net cash provided by operating activities	**358.7**	358.0
Cash Flows From Investing Activities		
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(128.8)**	(124.9)
Change in cash pool at parent	**(189.4)**	(17.5)
Sales of investments and other assets		4.9
Other	**(11.7)**	
Net cash used in investing activities	**(329.9)**	(137.5)
Cash Flows From Financing Activities		
Distribution to parent		(91.4)
Repayment of long-term debt	**(20.0)**	(124.9)
Preference stock dividends paid	**(6.6)**	(6.6)
Net cash used in financing activities	**(26.6)**	(222.9)
Net Increase (Decrease) in Cash and Cash Equivalents	**2.2**	(2.4)
Cash and Cash Equivalents at Beginning of Period	**8.2**	11.0
Cash and Cash Equivalents at End of Period	**$ 10.4**	$ 8.6

See Notes to Consolidated Financial Statements.

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 presentation of the financial position and 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 and fuel supply entities	Equity investment and guarantees	Prior to 2003
Power contract monetization entities	Power sale agreements, loans, and guarantees	March 2005

We discuss the nature of our involvement with the power contract monetization VIEs in detail below under *Customer Contract Restructuring*.

The following is summary information available as of June 30, 2005 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	$ 827.4	$ 218.5	$ 1,045.9
Total liabilities	733.4	74.7	808.1
Our ownership interest		44.8	44.8
Other ownership interests	94.0	99.0	193.0
Our maximum exposure to loss	81.4	70.3	151.7

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 June 30, 2005 consists of the following:

- outstanding loans and letters of credit totaling $94.5 million, the carrying amount of our investment totaling $44.5 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.

Customer Contract Restructuring

In March 2005, our merchant energy business closed a transaction in which we assumed from a counterparty two power sales contracts with existing VIEs. Under the contracts, we sell power to the VIEs which, in turn, sell that power to an electric distribution utility through 2013.

The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. The difference between the contract prices at which the VIEs purchase and sell power is used to service the debt of the VIEs, which totaled $721.0 million at June 30, 2005.

The market price for power at the closing of our transaction was higher than the contract price under the existing power sales contracts we assumed. Therefore, we received compensation totaling $308.5 million, equal to the net present value of the difference between the contract price under the power sales contracts and the market price of power at closing. We used a portion of this amount to settle $68.5 million of existing derivative liabilities with the same counterparty, and we also loaned $82.8 million to the holder of the equity in the VIEs. As a result, we received net cash at closing of $157.2 million. We also guaranteed our subsidiaries' performance under the power sales contracts.

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

		(In millions)
Gross compensation from original power sales contracts counterparty equal to fair value of power sales contracts at closing	$	308.5
Settlement of existing derivative liabilities		(68.5)
Third-party loan secured by equity in VIE		(82.8)
Net cash received at closing	$	157.2

We recorded the closing of this transaction in our financial statements as follows:

	Balance Sheet	**Cash Flows**
Fair value of power sales contracts assumed (designated as cash-flow hedge)	Risk management liabilities	Financing cash inflow
Settlement of existing derivative liabilities	Mark-to-market and risk management liabilities	Operating cash outflow
Third-party loan	Other assets	Investing cash outflow

We recorded the gross compensation we received to assume the power sales contracts as a financing cash inflow because it constitutes a prepayment for a portion of the market price of power which we will sell to the VIEs over the term of the contracts and does not represent a cash inflow from current period operating activities. We record the ongoing cash flows related to the sale of power to the VIE as a financing cash inflow in accordance with Statement of Financial Accounting Standards (SFAS) No. 149, *Amendment of FASB Statement No. 133 on Derivative and Hedging Activities*.

If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to us in lieu of repaying the loan. In this event, we would have the right to seek recovery of our losses from the electric distribution utility.

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 stock unit 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, in each period.

	Quarter Ended June 30,		**Six Months Ended June 30,**	
	2005	**2004**	**2005**	**2004**

	Quarter Ended June 30,		Six Months Ended June 30,	
		(In millions)		
Non-dilutive stock options	**0.1**	1.5	**0.1**	1.0
Dilutive common stock equivalent shares	**2.1**	0.9	**2.0**	1.0

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, performance-based units, and equity to officers, key employees, and members of the Board of Directors. As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*, we measure our stock-based compensation using the intrinsic value method in accordance with Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. We discuss these plans and accounting further in *Note 14* of our 2004 Annual Report on Form 10-K.

The following table presents the effect on net income and earnings per share had we applied the fair value recognition provisions of SFAS No. 123 to all outstanding stock options and stock awards in each period.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions, except per share amounts)			
Net income, as reported	**$ 121.7**	$ 128.2	**$ 242.4**	$ 194.4
Add: Stock-based compensation expense determined under intrinsic value method and included in reported net income, net of related tax effects	**5.5**	3.2	**10.0**	5.8
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	**(7.8)**	(5.3)	**(14.4)**	(9.4)
Pro-forma net income	**$ 119.4**	$ 126.1	**$ 238.0**	$ 190.8
Earnings per share:				
Basic as reported	**$ 0.69**	$ 0.76	**$ 1.37**	$ 1.15
Basic pro forma	**$ 0.67**	$ 0.75	**$ 1.34**	$ 1.13
Diluted as reported	**$ 0.68**	$ 0.76	**$ 1.35**	$ 1.15
Diluted pro forma	**$ 0.66**	$ 0.74	**$ 1.33**	$ 1.13

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123R, *Share-Based Payment*, which changed the accounting for stock-based compensation to require companies to expense stock options and other equity awards based on their grant-date fair values. We discuss SFAS No. 123R in more detail in the *Accounting Standards Issued* section on page 24.

Accretion of Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations,* provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

The change in our "Asset retirement obligations" liability during 2005 was as follows:

	(In millions)
Liability at January 1, 2005	$ 825.0
Accretion expense	30.4
Liabilities incurred	7.9
Liabilities settled	
Revisions to cash flows	
Other	
Liability at June 30, 2005	$ 863.3

In March 2005, the FASB issued Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations an intrepretation of FASB Statement No. 143*. We discuss FIN 47 in more detail in the *Accounting Standards Issued* section on page 24.

Workforce Reduction

We incurred costs related to workforce reduction efforts initiated in 2004. We discuss these costs in more detail in *Note 2* of our 2004 Annual Report on Form 10-K.

The following table summarizes the status of the involuntary severance liability:

		(In millions)
Severance liability balance at January 1, 2005	$	9.7
Amounts recorded as pension and postretirement liabilities		(3.6)
Net cash severance liability		6.1
Cash severance payments		(3.2)
Other		(0.2)
Severance liability balance at June 30, 2005	$	2.7

**Other represents adjustments to estimated severance liability based on additional information.*

Discontinued Operations

In March 2005, we reached an agreement in principle to sell to affiliates of The Southern Company (Southern) our Oleander generating facility, a four-unit peaking plant located in Florida. Our merchant energy business classified Oleander as held for sale and performed an impairment test under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* as of March 31, 2005. The impairment test indicated that the carrying value of the plant was higher than its fair value less costs to sell, and therefore in March 2005 we recorded an impairment charge of $4.8 million pre-tax as part of discontinued operations.

In June 2005, we completed the sale of this facility to Southern for $217.6 million. We recognized a gain on the sale of $1.5 million pre-tax as part of discontinued operations.

Presented in the table below are certain amounts related to Oleander that are included in "Income from discontinued operations" in our Consolidated Statements of Income.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In millions)		
Revenues	**$ 6.2**	$ 10.6	**$ 14.7**	$ 19.3
Income before income taxes	**3.0**	4.4	**8.5**	8.0
Net income	**1.9**	2.7	**5.3**	4.9
Pre-tax impairment charge			**(4.8)**	
After-tax impairment charge			**(3.0)**	
Pre-tax gain on sale	**1.5**		**1.5**	
After-tax gain on sale	**0.8**		**0.8**	
Income from discontinued operations, net of taxes	**2.7**	2.7	**3.1**	4.9

Business Combination

In April 2005, we acquired Cogenex Corporation from Alliant Energy Corporation. We include Cogenex with our other nonregulated businesses and have included their results in our consolidated financial statements since the date of acquisition. Cogenex is a North American energy services firm providing consulting and technology solutions to industrial, institutional, and governmental customers. We acquired 100% ownership of Cogenex for $36.4 million. We acquired cash of $14.4 million as part of the purchase.

Our preliminary purchase price allocation for the net assets acquired is as follows:

At April 1, 2005

	(In millions)
Cash	$ 14.4
Other Current Assets	12.0
Total Current Assets	26.4
Net Property, Plant and Equipment	
Other Assets	36.2
Total Assets Acquired	62.6
Current Liabilities	14.0
Deferred Credits and Other Liabilities	12.2
Net Assets Acquired	$ 36.4

Currently, we have not finalized the purchase price which could impact our purchase price allocation.

Asset Acquisition

In June 2005, we acquired working interests in gas producing fields in Texas and Alabama for approximately $211 million in cash and the assumption of below-market natural gas swaps and other liabilities totaling approximately $22 million. These working interests have independently estimated proved reserves of approximately 216 billion cubic feet equivalent. The Texas asset acquisition was for approximately a 70% working interest and the Alabama asset acquisition was for a 100% working interest.

Information by Operating Segment

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

Our nonregulated merchant energy business includes:

- full requirements load-serving sales of energy and capacity to utilities and commercial and industrial customers,
- structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs),
- gas retail energy products and services to commercial and industrial customers,
- fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities, fuel processing facilities, and power projects in the United States,
- products and services to upstream (exploration and production) and downstream (transportation and storage) natural gas customers,
- coal sourcing services for the variable or fixed supply needs of North American and international power generators, and
- operations and maintenance consulting services.

Our regulated electric business purchases, transmits, distributes, and sells electricity in Maryland.

Our regulated gas business purchases, transports, and sells natural gas in 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, real estate projects, and interests in a Panamanian distribution facility and in a fund that holds interests in two South American energy 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 in the table below.

	Reportable Segments					
	Merchant Energy Business	**Regulated Electric Business**	**Regulated Gas Business**	**Other Nonregulated Businesses**	**Eliminations**	**Consolidated**
				(In millions)		
For the three months ended June 30,						
2005						
Unaffiliated revenues	$ **2,825.4**	$ **465.1**	$ **141.7**	$ **116.6**	$	$ **3,548.8**
Intersegment revenues	**196.7**		**3.5**	**0.3**	**(200.5)**	
Total revenues	**3,022.1**	**465.1**	**145.2**	**116.9**	**(200.5)**	**3,548.8**
Income from discontinued operations Oleander	**2.7**					**2.7**
Net income (loss)	**95.4**	**25.4**	**(1.7)**	**2.6**		**121.7**
2004						
Unaffiliated revenues	$ 2,095.3	$ 477.2	$ 111.5	$ 103.3	$	$ 2,787.3
Intersegment revenues	262.3		1.1		(263.4)	
Total revenues	2,357.6	477.2	112.6	103.3	(263.4)	2,787.3
Income from discontinued operations Oleander	2.7					2.7
Loss from discontinued operations Hawaiian geothermal facility	(2.7)					(2.7)
Net income (loss)	106.5	25.2	(3.3)	(0.2)		128.2
For the six						

Reportable Segments

months ended June 30,						
2005						
Unaffiliated revenues	**$ 5,493.0**	**$ 956.6**	**$ 506.3**	**$ 222.7**	**$**	**$ 7,178.6**
Intersegment revenues	**422.2**		**4.7**	**0.5**	**(427.4)**	
Total revenues	**5,915.2**	**956.6**	**511.0**	**223.2**	**(427.4)**	**7,178.6**
Income from discontinued operations Oleander	**3.1**					**3.1**
Net income	**144.3**	**68.9**	**25.9**	**3.3**		**242.4**
2004						
Unaffiliated revenues	$ 4,217.3	$ 961.6	$ 429.4	$ 208.5	$	$ 5,816.8
Intersegment revenues	516.6		2.7		(519.3)	
Total revenues	4,733.9	961.6	432.1	208.5	(519.3)	5,816.8
Income from discontinued operations Oleander	4.9					4.9
Loss from discontinued operations Hawaiian geothermal facility	(49.0)					(49.0)
Net income (loss)	99.7	70.3	24.5	(0.1)		194.4

Pension and Postretirement Benefits

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
		(In millions)		
Components of net periodic pension benefit cost				
Service cost	**$ 11.4**	$ 11.4	**$ 22.5**	$ 20.0
Interest cost	**21.2**	21.8	**41.9**	41.1
Expected return on plan assets	**(25.6)**	(26.4)	**(49.5)**	(48.8)
Amortization of unrecognized prior service cost	**1.5**	1.6	**2.9**	2.9
Recognized net actuarial loss	**6.7**	3.7	**12.1**	7.2
Amount capitalized as construction cost	**(2.0)**	(1.2)	**(3.7)**	(1.9)
Net periodic pension benefit cost	**$ 13.2**	$ 10.9	**$ 26.2**	$ 20.5

Net periodic pension benefit cost excludes a reduction in termination benefits of $0.4 million in 2005. BGE's portion of our net periodic pension benefit cost was $5.4 million for the quarter ended June 30, 2005 and $2.6 million for the quarter ended June 30, 2004. BGE's portion of net periodic pension benefit cost was $10.5 million for the six months ended June 30, 2005 and $4.6 million for the six months ended June 30, 2004.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
		(In millions)		
Components of net periodic postretirement benefit cost				
Service cost	**$ 1.9**	$ 2.6	**$ 3.7**	$ 3.9
Interest cost	**6.1**	7.0	**11.8**	13.6
Amortization of transition obligation	**0.5**	0.7	**1.0**	1.3
Amortization of unrecognized prior service cost	**(0.9)**	(1.1)	**(1.7)**	(2.1)
Recognized net actuarial loss (gain)	**1.9**	(0.1)	**3.1**	1.9
Amount capitalized as construction cost	**(2.1)**	(1.6)	**(3.9)**	(4.0)
Net periodic postretirement benefit cost	**$ 7.4**	$ 7.5	**$ 14.0**	$ 14.6

BGE's portion of our net periodic postretirement benefit cost was $6.2 million for the quarter ended June 30, 2005 and $6.1 million for the quarter ended June 30, 2004. BGE's portion of our net periodic postretirement benefit costs was $12.0 million for the six months ended June 30, 2005 and $12.9 million for the six months ended June 30, 2004.

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 $3.1 million in pension benefit payments for our non-qualified pension plans and $29.5 million for retiree health and life insurance benefit payments during 2005. We contributed an additional $50.0 million to our qualified pension plans in March 2005, even though there was no Internal Revenue Service (IRS) required minimum contribution in 2005.

Financing Activities

During the first quarter of 2005, we entered into a new five-year credit facility totaling $1.5 billion. This new facility replaced two facilities totaling $1.1 billion a $640.0 million facility that would have expired in June 2005 and a $447.5 million facility that would have expired in June 2006. Constellation Energy also has an existing $800.0 million revolving credit facility expiring in June 2007 and a $300.0 million facility expiring in June 2009.

We use these facilities to ensure adequate liquidity to support our operations. Currently, we use the facilities to support letters of credit primarily for our merchant energy business. Additionally, we can borrow directly from the banks or use the facilities to allow the issuance of commercial paper.

These revolving credit facilities allow the issuance of letters of credit up to approximately $2.6 billion. In addition, BGE maintains $200.0 million in credit facilities. At June 30, 2005, letters of credit that totaled $958.7 million were issued under our facilities.

In July 2005, BGE announced a partial call of $1.9 million principal amount of its Remarketed Floating Rate Series Bonds due September 1, 2005 in connection with its annual sinking fund. The redemption will be made pursuant to the sinking fund provisions of BGE's mortgage. Bonds to be called were randomly selected by lot. Bonds called for the sinking fund will be redeemed in whole or in part on August 26, 2005 at the sinking fund call price of 100% of principal amount, plus accrued interest from June 1, 2005 to, but not including, August 26, 2005.

Additionally, under our employee benefit plans and shareholder investment plans we issued $45.2 million of common stock during the six months ended June 30, 2005.

Income Taxes

We have investments in facilities that manufacture solid synthetic fuel produced from coal as defined under Section 29 of the Internal Revenue Code for which we claim tax credits on our Federal income tax return. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained.

As of June 30, 2005, we have recognized cumulative tax benefits associated with Section 29 credits of $253.2 million, of which $27.4 million was recognized during the quarter ended June 30, 2005 and $52.0 million during the six months ended June 30, 2005.

Section 29 provides for a phase-out of the tax credit if average annual wellhead oil prices increase above certain levels. Each year, we are required to compare average annual wellhead oil prices per barrel as determined by the IRS (reference price) to an inflation adjusted oil price for the year, also determined by the IRS. The reference price is determined based on wellhead prices for all domestic oil production as published by the Energy Information Administration. Historically, the reference price has been $3 to $4 per barrel lower than the NYMEX price for light, sweet crude oil and currently it is $6 to $7 lower. For 2005, we estimate the credit reduction would begin if the reference price exceeds approximately $52 per barrel and would be fully phased out if the reference price exceeds approximately $66 per barrel. We currently believe that the 2005 reference price will not trigger a phase-out of the synthetic fuel tax credits in 2005 and, accordingly, we have recognized the full tax benefit of these credits in our Consolidated Statements of Income for the quarter and six months ended June 30, 2005.

Although we currently believe the 2005 reference price will not trigger a phase-out of synthetic fuel tax credits, we actively monitor and manage this exposure as part of our ongoing hedging activities. The objective of these activities is to reduce the potential losses we could incur if the reference price in a year exceeds a level triggering a phase-out of synthetic fuel tax credits.

While we believe the production and sale of synthetic fuel from all of our synthetic fuel facilities meet the conditions to qualify for tax credits under Section 29 of the Internal Revenue Code, we cannot predict the timing or outcome of any future challenge by the IRS, legislative or regulatory action, oil prices, the effectiveness of our hedging program, or the ultimate impact of such events on the Section 29 credits that we have claimed to date or expect to claim in the future, but the impact could be material to our financial results.

Our recognition of Section 29 credits reduced our statutory effective tax rate as detailed in the table below. 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 June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In millions)		
Income before income taxes (excluding BGE preference stock dividends)	**$ 155.5**	$ 116.6	**$ 318.3**	$ 271.3
Statutory federal income tax rate	**35%**	35%	**35%**	35%
Income taxes computed at statutory federal rate	**54.4**	40.8	**111.4**	94.9
(Decreases) increases in income taxes due to:				
Synthetic fuel tax credits	**(27.4)**	(22.7)	**(52.0)**	(44.8)
Synthetic fuel tax credits (2003)*		(35.9)		(35.9)
State income taxes, net of federal tax benefit	**6.2**	2.0	**13.2**	9.2
Other		0.9	**(0.2)**	2.8
Total income taxes	**$ 33.2**	$ (14.9)	**$ 72.4**	$ 26.2
Effective tax rate	**21.4%**	(12.8)%	**22.7%**	9.7%

**Credits associated with 2003 production at our South Carolina facility that were recognized in the second quarter of 2004 upon receipt of a favorable Private Letter Ruling from the IRS.*

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 has committed to long-term service agreements and other purchase commitments for our plants.

Our regulated businesses enter into various long-term contracts for the procurement of electricity and for the procurement, transportation, and storage of gas.

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 June 30, 2005, the total amount of commitments was $5,186.7 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 2017 and provide for the sale of energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants 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

The terms of our guarantees are as follows:

	Expiration				
	2005	2006-2007	2008-2009	Thereafter	Total
	(In millions)				
Competitive Supply	$ 3,070.5	$ 1,813.4	$ 306.3	$ 1,292.6	$ 6,482.8
Other	0.4	5.6	15.4	1,269.0	1,290.4
Total	$ 3,070.9	$ 1,819.0	$ 321.7	$ 2,561.6	$ 7,773.2

At June 30, 2005, we had a total of $7,773.2 million in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of our subsidiaries as described below. These guarantees do not represent our incremental obligations, but rather represent parental guarantees of existing subsidiary obligations, and we do not expect to fund the full amount under these guarantees.

Constellation Energy guaranteed $6,482.8 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. If the parent company was required to fund these subsidiary obligations, the total amount based on June 30, 2005 market prices would be $2,152.7 million. The recorded fair value of obligations in our Consolidated Balance Sheets for these guarantees was $904.1 million at June 30, 2005.

Constellation Energy guaranteed $939.3 million primarily on behalf of our nuclear generating facilities primarily related to nuclear insurance and for credit support to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

Constellation Energy guaranteed $59.5 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 June 30, 2005.

Our merchant energy business guaranteed $19.6 million for loans and other performance guarantees related to certain power projects in which we have an investment.

Our other nonregulated businesses guaranteed $8.7 million primarily for performance bonds.

BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At June 30, 2005, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million. The maximum amount of BGE's guarantee is $13.3 million.

BGE guaranteed the Trust Preferred Securities of $250.0 million of BGE Capital Trust II, an unconsolidated investment, as discussed in more detail in *Note 9* of our 2004 Annual Report on Form 10-K.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets was $929.1 million and not the $7.8 billion of total guarantees. We assess the risk of having to perform under these guarantees to be minimal.

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.

Metal Bank

In 1997, the EPA, under the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund"), issued a Record of Decision (ROD) for the proposed clean-up at the Metal Bank of America site, a metal reclaimer in Philadelphia. We had previously recorded a liability in our Consolidated Balance Sheets for BGE's 15.47% share of probable clean-up costs. Based on current settlement negotiations among the EPA and the potentially responsible parties involved at the site, we do not believe we will incur clean-up costs in excess of the amount recorded as a liability. The EPA and the potentially responsible parties, including BGE, are currently pursuing claims against Metal Bank of America for an equitable share of expected site remediation costs.

68th Street Dump

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List ("NPL"), 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, which has entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. While negotiations under this program are ongoing, the 68th Street Dump will not be placed on the NPL. At this stage, it is not possible to predict the outcome of those discussions or our share of the liability. However, the costs could have a material effect on our financial results.

Kane and Lombard

The EPA issued its ROD for the Kane and Lombard Drum site located in Baltimore, Maryland on September 30, 2003. The ROD specifies the clean-up plan for the site, consisting of enhanced reductive dechlorination, a soil management plan, and institutional controls. In July 2004, the EPA issued a Special Notice/Demand Letter to BGE and three other potentially responsible parties regarding implementation of the remedy. In response, the potentially responsible parties have begun negotiations with the EPA regarding the implementation. The total clean-up costs are estimated to be approximately $10 million. We estimate our current share of site-related costs to be 11.1% of the total. In December 2002, we recorded a liability in our Consolidated Balance Sheets for our share of the clean-up costs that we believe is probable. Our final share of the $10 million has not been determined and it may vary from the current estimate.

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 the remedial action plans, BGE estimates its probable clean-up costs will total $47 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 $14 million. Through June 30, 2005, 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 NOx, 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 evaluating the allegations in the NOVs and therefore it is not possible to determine the actual liability, if any, of the partnership that owns the Rio Bravo Rocklin facility.

Legal Proceedings

Western Power Markets

James M. Millar v. Allegheny Energy Supply, Constellation Power Source, Inc., High Desert Power Project, LLC, et al. On December 19, 2003, plaintiffs filed an amended complaint in Superior Court of California, County of San Francisco, naming for the first time, Constellation Power Source, Inc., renamed Constellation Energy Commodities Group, Inc. (CCG), and High Desert Power Project, LLC (High Desert), two of our subsidiaries, as additional defendants. The complaint is a putative class action on behalf of California electricity consumers and alleges that the defendant power suppliers, including CCG and High Desert, violated California's Unfair Competition Law in connection with certain long-term power contracts that the defendants negotiated with the California Department of Water Resources in 2001 and 2002. Notwithstanding the amended long-term power contracts and the releases and settlement agreements negotiated at the time of such amendments, the plaintiff seeks to have the Court certify the case as a class action and to order the repayment of any monies that were acquired by the defendants under the long-term contracts or the amended long-term contracts by means of unfair competition in violation of California law. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we cannot predict the timing, or outcome, of this case, or its possible effect on our financial results.

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 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 has appealed the dismissal of the action to the Ninth Circuit Court of Appeals. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we cannot predict the timing, or outcome, of this case, or its possible effect on our financial results.

Wholesale Electricity Antitrust Cases

In connection with a proceeding originally filed in March 2002, Reliant Energy Services (Reliant) and certain of its affiliates filed to join CCG and 29 other companies as cross-defendants in a proceeding entitled *Wholesale Electricity Antitrust Cases I and II,* which is now pending in the Superior Court of the State of California, County of San Diego, Case Nos. 4204 and 4205. The proceeding is a putative class action brought by various plaintiffs on behalf of California residents and alleges claims under certain California antitrust and fair competition laws. In general, the plaintiffs allege that Reliant and the other original defendants engaged in certain anti-competitive actions causing prices not reflective of market in the California electricity markets. Motions to dismiss the cases have been recently filed by the original defendants, and counsel has entered its appearance in this action in June 2005 for CCG. No action is required by CCG or the other cross-defendants until the court addresses the pending motions to dismiss filed by the original defendants. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. However, we cannot predict the timing, or outcome, of this case, or its possible effect on our financial results.

Mercury

Beginning in 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 have been filed to date, with each case seeking $90 million in damages from the group of defendants.

In a ruling applicable to all but several of the cases, the Circuit Court for Baltimore City dismissed with prejudice all claims against BGE and Constellation Energy and entered into a stay of the proceedings as they relate to other defendants. 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 actions vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Employment Discrimination

Miller, et. al. v. Baltimore Gas and Electric Company, et al. This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy, Constellation Nuclear Power Plants, Inc. and Calvert Cliffs Nuclear Power Plant, Inc. are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant, Inc. The parties have reached a settlement which has been approved by the Court. Under the settlement, Calvert Cliffs Nuclear Power Plant, Inc. will modify certain employment practices and we have agreed to pay a settlement amount that is not material to our financial results.

Asbestos

Since 1993, BGE has been involved in several actions concerning asbestos. These actions are based on the theory of "premises liability," alleging that BGE knew of and exposed individuals to asbestos in the course of the construction of certain power plants constructed by independent contractors on behalf of BGE.

BGE and numerous other parties are defendants in these cases. Approximately 515 individuals who were never employees of BGE have filed 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 in these actions. To date, claims of 42 asbestos plaintiffs have been settled for amounts that were not significant and approximately 319 were dismissed without payment. The remaining claims are currently pending in state courts in Maryland and Pennsylvania.

BGE does not know the specific facts necessary for it to assess its potential liability for the above referenced pending cases, such as the identity of the facilities at which the plaintiffs allegedly worked as contractors, the names of plaintiffs' employers, the dates on which the exposure allegedly occurred and the facts and circumstances relating to the alleged exposure.

Until the relevant facts for the above referenced pending cases are established, we cannot determine if the pending cases will be dismissed prior to trial, be postponed or be settled, and 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.

There has been no activity related to certain third party claims filed against BGE by Pittsburgh Corning Corp. (PCC) since PCC filed bankruptcy in April 2000. In addition, we do not believe that any amounts payable under claims made by PCC would have a material effect on our, or BGE's, financial results.

Canadian Environmental Class Action

Christopher M. Robinson, et. al. v. Ontario Power Generation Inc., et. al. On June 30, 2005, three individuals filed a class action in the Superior Court of Justice in Ontario, Canada against 21 companies, including Constellation Power Source Generation, Inc. (CPSG), one of our subsidiaries. The complaint alleges claims on behalf of residents of Ontario, Canada that have allegedly suffered adverse health effects as a result of emissions of sulfur dioxide, nitrogen oxide and particulate matter from approximately 60 different coal-fired power plants operating in Ontario, Michigan, Ohio, Pennsylvania, Kentucky, and West Virginia. CPSG is named as a defendant as a result of its ownership interests in two coal-fired power plants located in Pennsylvania. The complaint requests past damages of approximately Cdn$50 billion plus future annual damages of approximately Cdn$4 billion until trial. We believe that we have meritorious defenses to this action and intend to defend against it vigorously. We cannot predict the timing, or outcome, of this case, or its possible effect on our financial results.

Insurance

Our nuclear and non-nuclear property insurance policies were renewed effective July 1, 2005. Our non-nuclear property insurance annual aggregate limit for non-certified acts of terrorism increased to $1 billion from $333.3 million. Our excess nuclear property coverage changed to include a clause where Calvert Cliffs and Nine Mile Point share $1 billion of total excess coverage in the unlikely event of two property losses exceeding the full limit. Below is a description of our current coverage for nuclear and non-nuclear property insurance.

Non-Nuclear Property Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Act of 2002. Certified acts of terrorism are determined by the Secretary of State and Attorney General of the United States and primarily are based upon the occurrence of significant acts of international terrorism. Our conventional property insurance program also provides coverage for non-certified acts of terrorism up to an annual aggregate limit of $1.0 billion. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results.

Nuclear Property Insurance

Our policies provide $500 million in primary coverage at each nuclear plant Calvert Cliffs, Nine Mile Point, and Ginna. In addition, we maintain $1.77 billion of excess coverage at Ginna and $2.25 billion in excess coverage under a blanket excess program offered by the industry mutual insurer at both Calvert Cliffs and Nine Mile Point. Under the blanket excess policy, Calvert Cliffs and Nine Mile Point share $1.0 billion of the total $2.25 billion of excess property coverage. Therefore, in the unlikely event of two full limit property damage losses at Calvert Cliffs and Nine Mile Point, we would recover $4.5 billion instead of $5.5 billion. This coverage currently is purchased through the industry mutual insurance company. If accidents at plants insured by the mutual insurance company cause a shortfall of funds, all policyholders could be assessed, with our share being up to $91.7 million.

Losses resulting from non-certified acts of terrorism are covered as a common occurrence, meaning that if non-certified terrorist acts occur against one or more commercial nuclear power plants insured by our nuclear property insurance company within a 12-month period, they would be treated as one event and the owners of the plants where the acts occurred would share one full limit of liability (currently $3.24 billion).

We discuss our other nuclear insurance programs in *Note 12* of our 2004 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 2004 Annual Report on Form 10-K.

Interest Rates

We use interest rate swaps to manage our interest rate exposure associated with new debt issuances 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, *Accounting for Derivative Instruments and Hedging Activities, as amended,* with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in "Accumulated other comprehensive income" in our Consolidated Balance Sheets, in anticipation of planned financing transactions. We reclassify gains and losses on the hedges from "Accumulated other comprehensive income" 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 income" includes net unrealized pre-tax gains on interest rate cash-flow hedges totaling $16.8 million at June 30, 2005 and $18.3 million at December 31, 2004. We expect to reclassify $2.9 million of pre-tax net gains on these cash-flow hedges from "Accumulated other comprehensive income" into "Interest expense" during the next twelve months. We had no hedge ineffectiveness on these swaps.

During 2004, to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps qualifying as fair value hedges relating to $450 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 $18.5 million at June 30, 2005 and $13.3 million at December 31, 2004 and was recorded as an increase in our "Risk management assets" and "Long-term debt." We have not recognized any hedge ineffectiveness on these interest rate swaps.

Commodity Prices

At June 30, 2005, our merchant energy business had designated certain purchase and sale contracts as cash-flow hedges of forecasted transactions for the years 2005 through 2013 under SFAS No. 133.

Under the provisions of SFAS No. 133, we record gains and losses on energy derivative contracts designated as cash-flow hedges of forecasted transactions in "Accumulated other comprehensive income" in our Consolidated Balance Sheets prior to the settlement of the anticipated hedged physical transaction. We reclassify these gains or losses into earnings upon settlement of the underlying hedged transaction. We record derivatives used for hedging activities from our merchant energy business in "Risk management assets and liabilities" in our Consolidated Balance Sheets.

At June 30, 2005, our merchant energy business had net unrealized pre-tax losses of $129.9 million on these hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $405.6 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at June 30, 2005. However, the actual amount reclassified into earnings could vary from the amounts recorded at June 30, 2005 due to future changes in market prices.

We recognized into earnings a pre-tax gain of $0.8 million for the quarter ended June 30, 2005 and a pre-tax gain of $5.0 million for the quarter ended June 30, 2004 related to the ineffective portion of our hedges.

We recognized into earnings a pre-tax gain of $12.4 million for the six months ended June 30, 2005 and a pre-tax gain of $20.9 million for the six months ended June 30, 2004 related to the ineffective portion of our hedges. In addition, during the six months ended June 30, 2005, we terminated a contract previously designated as a cash-flow hedge. The forecasted transaction originally hedged is no longer probable and as a result we recognized a pre-tax loss of $6.1 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. For the quarter ended June 30, 2005, we had unrealized pre-tax gains of $1.1 million and unrealized pre-tax losses of $1.2 million due to hedge ineffectiveness, resulting in a pre-tax net loss of $0.1 million recognized into earnings. For the six months ended June 30, 2005, we had unrealized pre-tax gains of $2.6 million and unrealized pre-tax losses of $2.1 million due to hedge ineffectiveness, resulting in a pre-tax gain of $0.5 recognized into earnings. We record changes in fair value of these hedges as a component of "Fuel and purchased energy expenses" in our Consolidated Statements of Income.

Accounting Standards Issued

SFAS No. 123 Revised

In December 2004, the FASB issued SFAS No. 123 Revised (SFAS No. 123R), *Share-Based Payment*. SFAS No. 123R revises SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB No. 25, *Accounting for Stock Issued to Employees*. SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees. Equity-based compensation awards include stock options, restricted stock, and any other share-based payments. Under SFAS No. 123R, we must recognize compensation cost over the period during which an employee is required to provide service in exchange for the award. We estimate the fair value of employee stock options using option-pricing models adjusted for the unique characteristics of those instruments.

We previously disclosed in our 2004 Annual Report on Form 10-K that we planned to adopt SFAS No. 123R effective July 1, 2005. However, based on Final Rule 74 issued by the Securities and Exchange Commission in April 2005, which delayed the implementation of SFAS No. 123R, we currently plan to adopt SFAS No. 123R effective January 1, 2006.

We expect to adopt SFAS No. 123R using the Modified Prospective Application method without restatement of prior periods. Under this method, we will begin to amortize compensation cost for the remaining portion of our outstanding awards on the adoption date for which the requisite service has not yet been rendered. Compensation cost for these awards will be based on the fair value of those awards as disclosed on a pro-forma basis under SFAS No. 123 in the *Stock-Based Compensation* section on page 13. We will account for awards that are granted, modified, or settled after the adoption date in accordance with SFAS No. 123R.

Currently, we are evaluating the impact of adopting this standard on our financial results. However, we do not believe the impact of this standard on our ongoing operating results will be materially different than the results as disclosed on a pro-forma basis in the *Stock-Based Compensation* section on page 13.

FIN 47

In March 2005, the FASB issued FIN 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143.* FIN 47 is effective December 31, 2005. FIN 47 clarifies that asset retirement obligations that are conditional upon a future event are subject to the provisions of SFAS No. 143. Under SFAS No. 143, we are required to recognize an estimated liability for legal obligations associated with the retirement of long-lived assets. While we are still evaluating the impact of FIN 47, we believe we may be required to record asset retirement obligations relating to asbestos removal at certain of our facilities. We are unable to quantify the impact of FIN 47 at this time; however, the impact could be material to our financial results.

Related Party Transactions BGE

Income Statement

BGE provides standard offer service to those customers that do not choose an alternative electric supplier. Our wholesale marketing and risk management operation provided BGE with the energy and capacity required to meet its commercial and industrial standard offer service obligations through June 30, 2004, and provides the energy and capacity required to meet its residential standard offer service obligations through June 30, 2006. Bidding to supply BGE's standard offer service to commercial and industrial customers beyond June 30, 2004, and to residential customers beyond June 30, 2006, will occur from time to time through a competitive bidding process approved by the Maryland Public Service Commission. Our wholesale marketing and risk management operation is supplying a portion of BGE's standard offer service obligation to commercial and industrial customers.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004

	Quarter Ended June 30,		Six Months Ended June 30,	
		(In millions)		
Purchased energy	**$ 185.4**	$ 254.1	**$ 398.5**	$ 494.5

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 June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In millions)		
Charges to BGE	**$ 27.7**	$ 25.3	**$ 52.7**	$ 42.9

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. BGE had invested $317.3 million at June 30, 2005 and $127.9 million at December 31, 2004 under this arrangement.

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 pension plan.

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 a North American 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 14.

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.

Our 2004 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.

Critical accounting policies 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. Our critical accounting policies include revenue recognition/mark-to-market accounting, evaluation of assets for impairment and other than temporary decline in value, and asset retirement obligations.

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 six months ended June 30, 2005 and 2004. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

We describe changes to our business environment during the year.

We highlight significant events that occurred in 2005 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 shift toward customer choice, 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 50. We discuss our market risks in the *Market Risk* section on page 45.

In this section, we discuss in more detail events which have impacted our business during the six months ended June 30, 2005.

Regulation by the Maryland PSC

Base Rates

On April 29, 2005, BGE filed an application for a $52.7 million annual increase in our gas base rates. The Maryland Public Service Commission (Maryland PSC) is currently reviewing our application and is expected to issue an order by late December 2005. We cannot provide assurance that the Maryland PSC will approve the rate increase request, or if it does, that it will grant BGE the full amount requested.

Standard Offer Service Provider of Last Resort (POLR)

In June 2005, BGE, along with other parties, requested the Maryland PSC to extend POLR service through May 2008 for those commercial and industrial customers for which market-based standard offer service is scheduled to expire at the end of May 2006. The terms of the extended service would be substantially the same as under the existing service, except that wholesale bidding for service to some customers would be conducted more frequently. The Maryland PSC has scheduled hearings in August 2005 to consider the request, and a decision is anticipated by the end of the third quarter of 2005. We cannot predict the outcome of this proceeding or its impact on our, or BGE's, financial results.

We discuss Standard Offer Service Provider of Last Resort in more detail in *Item 1. Business Electric Regulatory Matters and Competition* section of our 2004 Annual Report on Form 10-K.

Regulation in Other States

Proposition 80 has been placed on the ballot for the November 8, 2005 special election in California. If passed and enacted into law, Proposition 80 would greatly expand the California Public Utility Commission's authority over competitive supply providers in California. At this time we cannot determine the likelihood of success of the ballot initiative, nor determine, if enacted, the ultimate effect of Proposition 80 on the California business of our competitive supply operation. However, if enacted, Proposition 80 could have a material effect on our financial results.

Federal Regulation

Federal Energy Regulatory Commission (FERC)

In May 2005, FERC issued an order accepting BGE's joint application to have network transmission rates established through a formula that tracks costs instead of through fixed rates. The formula approach was effective as of June 1, 2005, and the implementation of these rates did not have a material effect on our, or BGE's, financial results. The use of the formula approach that was implemented is subject to refund based on the outcome of a hearing before an administrative law judge. We cannot predict the outcome of this hearing or whether FERC will ultimately affirm the judge's decision.

Federal Energy Legislation

The Energy Policy Act of 2005 was passed by both the U.S. Senate and the U.S. House of Representatives in July 2005. The President is expected to sign the legislation on August 8, 2005. The legislation encourages investments in energy production and delivery infrastructure, including further development of competitive wholesale energy markets, and promotes the use of a diverse mix of fuels and renewable technologies to generate electricity, including federal support and tax incentives for clean coal, nuclear, and renewable power generation. We are still reviewing all aspects of the legislation.

Environmental Matters

Air Quality

<u>*National Ambient Air Quality Standards (NAAQS)*</u>

The NAAQS are federal air quality standards that establish maximum ambient air concentrations for the following specific pollutants: ozone (smog), carbon monoxide, lead, particulates, sulfur dioxide (SO_2), and nitrogen dioxide (NO_2). Our generating facilities are primarily affected by ozone and particulates standards. Ozone is formed when sunlight interacts with emissions of nitrogen oxides (NO_x) and volatile organic compounds (such as from motor vehicle exhaust). Our generating facilities are subject to various permits and programs meant to achieve or preserve attainment of the standards for all these pollutants.

In order for states to achieve compliance with the NAAQS, the Environmental Protection Agency (EPA) adopted the Clean Air Interstate Rule (CAIR) in March 2005 to further reduce ozone and fine particulate pollution by addressing the interstate transport of SO_2 and NO_x emissions from fossil fuel-fired plants located primarily in the Eastern United States. The NO_x reduction requirements will be phased-in starting in 2009 with both annual and ozone season reduction requirements. The phase-in will be complete by 2015. The SO_2 reduction requirements will be phased-in starting in 2010 with the phase-in complete by 2015. According to the EPA, when fully implemented, CAIR will reduce SO_2 emissions in the affected states by over 70 percent and reduce NO_x emissions by over 60 percent from 2003 levels. Although CAIR provides the overall reduction requirements for SO_2 and NO_x, we do not yet know the impact on our facilities as that will be determined by the affected states in which our facilities operate. We are in the process of evaluating the impact of the rules on our financial results based on the information currently available to us. As of the filing date of this report, we believe that the environmental capital expenditure estimates provided in *Item 1. Business Environmental Matters* in our 2004 Annual Report on Form 10-K remain reasonable projections. Additional federal and/or state legislation or regulation requiring further emission reductions from our facilities could be adopted.

In May 2005, the EPA adopted a stricter NAAQS for ozone. States will be required to submit plans to the EPA to meet the new standard by 2007, at which time the standard will take effect. We are unable to determine the impact that complying with the stricter NAAQS for ozone will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standard. In transitioning to the stricter NAAQS for ozone, the EPA has delayed the requirement that states impose fees on generating facilities located in areas that have not met the NAAQS for ozone. Such fees could have been assessed on certain of our generating facilities located in Maryland and California beginning in 2006, but now will not be assessed prior to 2010.

In June 2005, the EPA finalized its rules relating to regional haze, which address emissions of SO_2, NO_x and particulate matter. However, adoption of CAIR by states is expected to meet the emissions reduction requirements under the regional haze rules. We expect Maryland and Pennsylvania, where we own several generating facilities, to adopt CAIR. As a result, we believe the adoption of the regional haze rules by the EPA will not have a material effect on our financial results.

Hazardous Air Emissions

The Clean Air Act requires the EPA to evaluate the public health impacts of hazardous air emissions from electric steam generating facilities. In March 2005, the EPA finalized regulations to reduce the emissions of mercury from coal-fired facilities. Under the Clean Air Mercury Rule (CAMR), the EPA has decided to regulate mercury through a market-based cap and trade program that will reduce nationwide utility emissions of mercury in two phases. Unlike the proposed rule, the final CAMR does not address emissions of nickel. The first phase of the program will begin in 2010. Additional mercury reductions will be required in the second phase of the program starting in 2018. According to the EPA, the CAMR will reduce mercury emissions from all affected coal-fired power plants by about 19 percent from 1999 levels in 2010, mostly from controls installed to comply with CAIR. The EPA expects total mercury reductions from all affected coal-fired plants of about 69 percent from 1999 levels by 2018. The CAMR will affect all coal or waste coal fired boilers at our generating facilities. Although our planned capital expenditures for compliance with CAIR are anticipated to enable us to substantially meet the mercury reduction requirements under the first phase of the cap and trade program, the overall cost of compliance with the CAMR, including complying with

the requirements under the second phase of the program, could be material. We are currently evaluating the impact of the rule on our financial results.

You will find details of our environmental matters in the *Environmental Matters* section of the *Notes to Consolidated Financial Statements* beginning on page 19 and in our 2004 Annual Report on Form 10-K in *Item 1. Business Environmental Matters.*

Accounting Standards Issued

We discuss recently issued accounting standards in the *Accounting Standards Issued* section of the *Notes to Consolidated Financial Statements* on page 24.

Events of 2005

Discontinued Operations

In June 2005, we sold our Oleander generating facility to affiliates of The Southern Company for $217.6 million. We discuss the sale of the Oleander generating facility in more detail in the *Notes to Consolidated Financial Statements* beginning on page 13.

Business Combination and Asset Acquisition

In April 2005, we acquired Cogenex Corporation from Alliant Energy Corporation. In June 2005, we acquired working interests in gas producing fields in Texas and Alabama.

We discuss these transactions in more detail in the *Notes to Consolidated Financial Statements* on page 14.

Pension Plan Assets

Our actual return on pension plan assets was 1.1% through June 30, 2005. In addition, we contributed $50 million, or approximately $30 million after-tax, to our pension plans in 2005.

If pension plan assets earn 4.5% during the second half of 2005, or one-half of our 9% annual return on pension assets assumption, and interest rates remain at current levels, an after-tax charge to equity of approximately $50 million would be recorded at December 31, 2005 to increase our additional minimum pension liability. This primarily results from the decline in interest rates since year-end 2004, which in turn increases our pension liability. The amount ultimately recorded will be determined by our actual 2005 return on pension plan assets, which depends on the performance of the financial markets during 2005, and our discount rate assumption, which depends on year-end interest rates. As a result, the charge to equity, if any, could be materially different than our current estimate.

Results of Operations for the Quarter and Six Months Ended June 30, 2005 Compared with the Same Periods of 2004

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 on page 41.

Overview

Results

	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions, after-tax)			
Merchant energy	**$ 92.7**	$ 106.5	**$ 141.2**	$ 143.8
Regulated electric	**25.4**	25.2	**68.9**	70.3
Regulated gas	**(1.7)**	(3.3)	**25.9**	24.5
Other nonregulated	**2.6**	(0.2)	**3.3**	(0.1)
Income from Continuing Operations	**119.0**	128.2	**239.3**	238.5
Income from discontinued operations (see Notes)	**2.7**	2.7	**3.1**	4.9
Loss from discontinued operations		(2.7)		(49.0)
Net Income	**$ 121.7**	$ 128.2	**$ 242.4**	$ 194.4
Special Items Included in Operations				
Recognition of 2003 synthetic fuel tax credits	**$**	$ 35.9	**$**	$ 35.9

Quarter Ended June 30, 2005

Our total net income for the quarter ended June 30, 2005 decreased $6.5 million, or $0.08 per share, compared to the same period of 2004 mostly because of the following:

- Our merchant energy business recognized $35.9 million of 2003 synthetic fuel tax credits in the second quarter of 2004 which had a positive impact in that period.
- We had lower earnings of $5.6 million after-tax at our R. E. Ginna Nuclear Plant (Ginna) facility primarily due to the 2005 refueling outage.
- We had lower earnings due to the absence of a favorable bankruptcy settlement in 2004 that had a positive impact in that period.

These decreases were partially offset by the following:

- We had higher earnings of approximately $29 million after-tax mostly due to lower operating expenses at our Calvert Cliffs and Nine Mile Point facilities because of productivity initiatives.
- We had higher earnings of approximately $10 million after-tax at our generation fleet including our Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) related to the timing of a refueling outage which occurred in the first quarter of 2005 compared to the second quarter of 2004.

Earnings per share was also impacted by additional dilution resulting from the issuance of common stock, including 6.0 million shares issued on July 1, 2004 related to the acquisition of Ginna.

Six Months Ended June 30, 2005

Our total net income for the six months ended June 30, 2005 increased $48.0 million, or $0.20 per share, compared to the same period of 2004 mostly because of the following:

- We recorded a $49.0 million after-tax, or $0.29 per share, loss from discontinued operations on our Hawaiian geothermal facility in the first quarter of 2004 which had a negative impact in that period.
- We realized higher gross margin from our wholesale marketing and risk management operation, which included the monetization of a power purchase agreement.
- We had higher earnings of approximately $38 million after-tax at our Calvert Cliffs and Nine Mile Point facilities primarily due to productivity initiatives and higher generation mostly because of fewer refueling outage days.

These increases were partially offset by the following:

- Our merchant energy business recognized $35.9 million of 2003 synthetic fuel tax credits in the second quarter of 2004 which had a positive impact in that period.
- We had lower earnings due to the higher pre-tax losses of $13.5 million associated with economic hedges that do not qualify for cash-flow hedge accounting treatment. We discuss these economic hedges in more detail in the *Mark-to-Market Revenues* section on page 34.
- We had lower earnings of $7.5 million after-tax at our Ginna facility primarily due to the 2005 refueling outage.

Earnings per share was also impacted by additional dilution resulting from the issuance of common stock, including 6.0 million shares issued on July 1, 2004 related to the acquisition of Ginna.

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 2004 Annual Report on Form 10-K.

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 2004 Annual Report on Form 10-K. We summarize our 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 on a net basis 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 our contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our revenues in the *Competitive Supply Mark-to-Market Revenues* section on page 33. We discuss mark-to-market accounting and the accounting policies for the merchant energy business further in the *Critical Accounting Policies* section and in *Note 1* of our 2004 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In millions)		
Revenues	**$ 3,022.1**	$ 2,357.6	**$ 5,915.2**	$ 4,733.9
Fuel and purchased energy expenses	**(2,445.7)**	(1,832.8)	**(4,828.6)**	(3,779.9)
Operating expenses	**(328.5)**	(317.2)	**(658.4)**	(588.1)
Depreciation and amortization	**(65.4)**	(58.5)	**(128.3)**	(112.8)
Accretion of asset retirement obligations	**(15.3)**	(12.4)	**(30.4)**	(23.5)
Taxes other than income taxes	**(25.5)**	(20.4)	**(50.0)**	(41.3)
Income from Operations	**$ 141.7**	$ 116.3	**$ 219.5**	$ 188.3
Income from Continuing Operations (after-tax)	**$ 92.7**	$ 106.5	**$ 141.2**	$ 143.8
Income from discontinued operations (after-tax)	**2.7**	2.7	**3.1**	4.9
Loss from discontinued operations (after-tax)		(2.7)		(49.0)
Net Income	**$ 95.4**	$ 106.5	**$ 144.3**	$ 99.7
Special Items Included in Operations (after-tax)				
Recognition of 2003 synthetic fuel tax credits	**$**	$ 35.9	**$**	$ 35.9

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 15 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. The difference between revenues and fuel and purchased energy 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 occasionally 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 Interconnection (PJM) region for which the output is primarily used to serve BGE. 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 generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements, including the Nine Mile Point, Ginna, University Park, and High Desert facilities.

Retail Competitive Supply our operation that provides electric and gas energy products and services to commercial and industrial customers.

Wholesale Competitive Supply our marketing and risk management operation that provides energy products and services outside the Mid-Atlantic Region primarily to distribution utilities, power generators, and other wholesale customers.

Other our investments in qualifying facilities and domestic power projects and our operations and maintenance consulting services.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
	(Dollar amounts in millions)			
Revenues:				
Mid-Atlantic Region	**$ 495.4**	$ 425.4	**$ 990.2**	$ 856.7
Plants with Power Purchase Agreements	**191.9**	148.4	**384.4**	273.4
Competitive Supply				
Retail	**1,403.0**	954.3	**2,723.5**	1,980.0
Wholesale	**929.1**	820.1	**1,797.6**	1,594.2
Other	**2.7**	9.4	**19.5**	29.6
Total	**$ 3,022.1**	$ 2,357.6	**$ 5,915.2**	$ 4,733.9
Fuel and purchased energy expenses:				
Mid-Atlantic Region	**$ (227.8)**	$ (172.2)	**$ (541.2)**	$ (399.7)
Plants with Power Purchase Agreements	**(18.6)**	(12.6)	**(33.9)**	(22.5)
Competitive Supply				
Retail	**(1,335.4)**	(888.2)	**(2,592.9)**	(1,857.9)
Wholesale	**(863.9)**	(759.8)	**(1,660.6)**	(1,499.8)
Other				
Total	**$ (2,445.7)**	$ (1,832.8)	**$ (4,828.6)**	$ (3,779.9)

Gross Margin:		**% of Total**		**% of Total**		**% of Total**		**% of Total**
Mid-Atlantic Region	**$ 267.6**	**46%**	$ 253.2	48%	**$ 449.0**	**41%**	$ 457.0	48%
Plants with Power Purchase Agreements	**173.3**	**30**	135.8	26	**350.5**	**32**	250.9	26
Competitive Supply								
Retail	**67.6**	**12**	66.1	13	**130.6**	**12**	122.1	13
Wholesale	**65.2**	**11**	60.3	11	**137.0**	**13**	94.4	10
Other	**2.7**	**1**	9.4	2	**19.5**	**2**	29.6	3
Total	**$ 576.4**	**100%**	$ 524.8	100%	**$ 1,086.6**	**100%**	$ 954.0	100%

Mid-Atlantic Region

	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions)			
Revenues	**$ 495.4**	$ 425.4	**$ 990.2**	$ 856.7
Fuel and purchased energy expenses	**(227.8)**	(172.2)	**(541.2)**	(399.7)
Gross margin	**$ 267.6**	$ 253.2	**$ 449.0**	$ 457.0

The increase in gross margin during the quarter ended June 30, 2005 compared to the same period of 2004 is primarily due to higher generation at Calvert Cliffs mostly because of the timing of the refueling outage, which occurred in the first quarter of 2005 compared to the second quarter of 2004, resulting in higher gross margin of approximately $28 million, offset in part by lower competitive transition charge (CTC) revenues of approximately $11 million.

The decrease in gross margin during the six months ended June 30, 2005 compared to the same period of 2004 is primarily due to lower CTC revenues of approximately $14 million.

Plants with Power Purchase Agreements

	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions)			
Revenues	**$ 191.9**	$ 148.4	**$ 384.4**	$ 273.4
Fuel and purchased energy expenses	**(18.6)**	(12.6)	**(33.9)**	(22.5)
Gross margin	**$ 173.3**	$ 135.8	**$ 350.5**	$ 250.9

The increase in gross margin during the quarter ended June 30, 2005 compared to the same period of 2004 was primarily due to $28.0 million from Ginna, which was acquired in June 2004. This increase in gross margin at Ginna includes an increase in revenues of $30.4 million. We also had higher gross margin of $5.5 million at our Nine Mile Point facility that benefited from higher generation in the second quarter of 2005 compared to 2004.

The increase in gross margin during the six months ended June 30, 2005 compared to the same period of 2004 was primarily due to $74.7 million from Ginna. This increase in gross margin at Ginna includes an increase in revenues of $79.4 million. We also had higher gross margin of $15.3 million at our Nine Mile Point facility that benefited from higher generation due to fewer refueling outage days and the absence of an unplanned outage that occurred in January 2004.

Competitive Supply

Retail

	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions)			
Accrual revenues	**$ 1,405.1**	$ 957.2	**$ 2,726.7**	$ 1,984.0

	Quarter Ended June 30,		Six Months Ended June 30,	
Mark-to-market revenues	**(2.1)**	(2.9)	**(3.2)**	(4.0)
Fuel and purchased energy expenses	**(1,335.4)**	(888.2)	**(2,592.9)**	(1,857.9)
Gross margin	**$ 67.6**	$ 66.1	**$ 130.6**	$ 122.1

The increase in gross margin from our retail competitive supply activities during the quarter ended June 30, 2005 compared to the same period of 2004 is primarily due to serving 5.2 million more megawatt hours, partially offset by lower realized contract margins per megawatt hour and a favorable bankruptcy settlement that had a positive impact in 2004.

The increase in gross margin from our retail competitive supply activities during the six months ended June 30, 2005 compared to the same period of 2004 is primarily due to serving 8.7 million more megawatt hours, partially offset by lower realized contract margins per megawatt hour and a favorable bankruptcy settlement that had a positive impact in 2004.

Wholesale

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In millions)		
Accrual revenues	**$ 882.6**	$ 803.6	**$ 1,728.6**	$ 1,568.4
Fuel and purchased energy expenses	**(863.9)**	(759.8)	**(1,660.6)**	(1,499.8)
Wholesale accrual activities	**18.7**	43.8	**68.0**	68.6
Mark-to-market revenues	**46.5**	16.5	**69.0**	25.8
Gross margin	**$ 65.2**	$ 60.3	**$ 137.0**	$ 94.4

We analyze our wholesale accrual and mark-to-market competitive supply activities separately on the next page.

Wholesale Accrual Activities

Our wholesale marketing and risk management operation had lower gross margin during the quarter ended June 30, 2005 compared to the same period of 2004 due to a decrease of approximately $37 million primarily in the New England region mostly because of the absence of several favorable items including settlements, power prices, and contracts that existed in 2004 that had a positive impact in that period, partially offset by a 2005 gain of approximately $12 million of newly originated and realized business in power, gas, and coal.

Our wholesale marketing and risk management operation's gross margin was about the same during the six months ended June 30, 2005 compared to the same period of 2004 due to a decrease of approximately $56 million primarily in the New England region mostly because of the absence of several favorable items including settlements, power prices, and contracts that existed in 2004 that had a positive impact in that period, offset by newly originated and realized business in power, gas, and coal in 2005. A substantial portion of newly originated gross margin related to the monetization of a power purchase agreement during the first quarter of 2005. The power purchase agreement would have otherwise delivered through December 2006. This sale for cash allowed us to eliminate performance risk by the counterparty under the original contract.

Mark-to-Market Revenues

Mark-to-market revenues include net gains and losses from origination 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 2004 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 revenues and earnings will fluctuate. We cannot predict these fluctuations, but the impact on our revenues and earnings could be material. We discuss our market risk in more detail in the *Market Risk* section on page 45. The primary factors that cause fluctuations in our mark-to-market revenues and earnings 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 revenues were as follows:

	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions)			
Unrealized revenues				
Origination transactions	**$ 7.7**	$ 9.6	**$ 9.6**	$ 9.6
Risk management				
Unrealized changes in fair value	**36.7**	4.0	**56.2**	12.2
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(73.6)**	(21.2)	**(61.8)**	(36.2)
Total risk management	**(36.9)**	(17.2)	**(5.6)**	(24.0)
Total unrealized revenues*	**(29.2)**	(7.6)	**4.0**	(14.4)
Realized revenues	**73.6**	21.2	**61.8**	36.2
Total mark-to-market revenues	**$ 44.4**	$ 13.6	**$ 65.8**	$ 21.8

* *Total unrealized revenues are the sum of origination transactions and total risk management.*

Origination gains arise from contracts that our wholesale marketing and risk management operation structures to meet the risk management needs of our customers. 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 structured transactions. The recognition of origination gains is dependent on the existence of observable market data that validates the initial fair value of the contract. Origination gains arose from 10 transactions during the quarter ended June 30, 2005, compared to 7 transactions during the same period of 2004. Origination gains arose from 25 transactions during the six months ended June 30, 2005 compared to 7 transactions during the same period of 2004.

As noted above, the recognition of origination gains is dependent on sufficient observable market data. 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 revenue we are able to recognize may vary from year to year as a result of the number, size, and market-price transparency of the individual transactions executed in any period.

Risk management revenues represent both realized and unrealized gains and losses from changes in the value of our entire portfolio. We discuss the changes in mark-to-market revenues below. We show the relationship between our revenues and the change in our net mark-to-market energy asset later in this section.

Mark-to-market revenues increased $30.8 million during the quarter ended June 30, 2005 compared to the same period of 2004 primarily due to an increase in unrealized changes in fair value mostly because of changes in the value of open positions as a result of energy prices, price volatility, and other factors. These increases in mark-to-market revenues include changes in the close-out adjustment of $12.3 million during the quarter ended June 30, 2005 compared to the same period of the prior year for transactions that 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 2004 Annual Report on Form 10-K.

Mark-to-market revenues increased $44.0 million during the six months ended June 30, 2005 compared to the same period of 2004 primarily due to an increase in unrealized changes in fair value mostly because of changes in the value of open positions as a result of energy prices, price volatility, and other factors. These increases in mark-to-market revenues include changes in the close-out adjustment of $36.9 million during the six months ended June 30, 2005 compared to the same period of the prior year for transactions that we have now observed sufficient market price information and/or we realized cash flows since the transactions' inception. These increases in mark-to-market revenues were partially offset by the impact of $13.5 million of higher mark-to-market losses on economic hedges that did not qualify for cash-flow hedge accounting treatment.

In the first half of 2005, increasing forward prices shifted value between accrual load-serving contracts and associated mark-to-market hedges, producing a timing difference in the recognition of earnings on these transactions. These mark-to-market hedges are economically effective; however, they do not qualify for cash-flow hedge accounting under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*. As a result, we recorded higher pre-tax losses of $13.5 million on the mark-to-market hedges during the six months ended June 30, 2005 compared to the same period of 2004. This mark-to-market loss is expected to be offset as we realize the related accrual load-serving contracts in cash in future periods.

Mark-to-Market Energy Assets and Liabilities

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

	June 30, 2005	**December 31, 2004**
	(In millions)	
Current Assets	**$ 626.1**	$ 567.3
Noncurrent Assets	**626.2**	359.8
Total Assets	**1,252.3**	927.1
Current Liabilities	**609.1**	559.7
Noncurrent Liabilities	**550.6**	315.0
Total Liabilities	**1,159.7**	874.7
Net mark-to-market energy asset	**$ 92.6**	$ 52.4

The following are the primary sources of the change in the net mark-to-market energy asset during the quarter and six months ended June 30, 2005:

	Quarter Ended June 30, 2005	**Six Months Ended June 30, 2005**
	(In millions)	
Fair value beginning of period	$ 74.9	$ 52.4

	Quarter Ended June 30, 2005	Six Months Ended June 30, 2005
Changes in fair value recorded as revenues		
Origination gains	$ 7.7	$ 9.6
Unrealized changes in fair value	36.7	56.2
Changes in valuation techniques		
Reclassification of settled contracts to realized	(73.6)	(61.8)
Total changes in fair value recorded as revenues	(29.2)	4.0
Changes in value of exchange-listed futures and options	4.6	(28.0)
Net change in premiums on options	26.8	52.5
Other changes in fair value	15.5	11.7
Fair value at end of period	$ 92.6	$ 92.6

Components of changes in the net mark-to-market energy asset that affected revenues include:

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 economic 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 revenue:

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.

The settlement terms of the net mark-to-market energy asset and sources of fair value as of June 30, 2005 are as follows:

	Settlement Term							
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Fair Value**
				(In millions)				
Prices provided by external sources (1)	$ 3.7	$ 17.0	$ 37.1	$ 24.6	$ (1.0)	$	$	$ 81.4
Prices based on models	(4.8)	(0.5)	(3.4)	17.0	3.2	(0.3)		11.2
Total net mark-to-market energy asset	$ (1.1)	$ 16.5	$ 33.7	$ 41.6	$ 2.2	$ (0.3)	$	$ 92.6

(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 above based upon the ability to obtain reliable prices for components of the risks in our contracts from external 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 on the next page.

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 purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2006, but up to 2009, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2006, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms primarily through 2006, but up to 2007, depending upon the region,
- forward purchases and sales of natural gas, coal, and oil for delivery terms primarily through 2007, but up to 2009, depending upon the commodity, 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 energy 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 and risk management 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 and risk management 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 June 30, 2005 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.

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:

	June 30, 2005	December 31, 2004
	(In millions)	
Current Assets	**$ 589.8**	$ 471.5
Noncurrent Assets	**478.3**	306.2
Total Assets	**1,068.1**	777.7
Current Liabilities	**272.2**	304.3
Noncurrent Liabilities	**1,148.2**	472.2
Total Liabilities	**1,420.4**	776.5
Net risk management (liability) asset	**$ (352.3)**	$ 1.2

The increase in our net risk management liability was due primarily to our assumption of power sale agreements in connection with a customer contract restructuring. We discuss the customer contract restructuring transaction in more detail in the *Notes to Consolidated Financial Statements* beginning on page 11.

Other

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Revenues	**$ 2.7**	$ 9.4	**$ 19.5**	$ 29.6

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 2004 Annual Report on Form 10-K.

We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* section on page 50. 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*.

If our strategy were to change from an intent to hold to an intent to sell for any of our equity-method investments in qualifying facilities or power projects, we would need to adjust their book value to fair value, and that adjustment could be material. If we were to sell these investments in the current market, we may have losses that could be material.

Operating Expenses

Our merchant energy business operating expenses increased $11.3 million during the quarter ended June 30, 2005 compared to the same period of 2004 mostly due to the following:

- an increase of $25.7 million due to Ginna which was acquired in June 2004, and
- an increase at our wholesale marketing and risk management operation and our retail commercial and industrial operation totaling $19.2 million primarily related to higher compensation and benefit costs and the impact of inflation on other costs.

These increases in expenses were partially offset by the following:

- lower operating expenses at our Calvert Cliffs facility of $24.8 million, primarily due to productivity initiatives and the timing of a refueling outage that occurred in the first quarter of 2005 compared to the second quarter of 2004, and
- lower operating expenses of $7.4 million at Nine Mile Point, primarily due to productivity initiatives including a lower number of employees and contractors.

Our merchant energy business operating expenses increased $70.3 million during the six months ended June 30, 2005 compared to the same period of 2004 mostly due to the following:

- an increase of $63.8 million due to Ginna, and
- an increase of $34.6 million at our wholesale marketing and risk management operation and our retail commercial and industrial operation primarily related to higher compensation and benefit costs and the impact of inflation on other costs.

These increases in expenses were partially offset by lower operating expenses of $29.9 million at Nine Mile Point primarily due to a lower number of employees and contractors.

Depreciation and Amortization Expense

Merchant energy depreciation and amortization expense increased $6.9 million during the quarter ended June 30, 2005 compared to the same period of 2004 mostly due to $3.7 million related to Ginna. We also had $1.7 million higher depreciation and amortization expense related to our South Carolina synthetic fuel facility during the quarter ended June 30, 2005 compared to the same period of 2004.

Merchant energy depreciation and amortization expenses increased $15.5 million during the six months ended June 30, 2005 compared to the same period of 2004 mostly due to $8.5 million related to Ginna. We also had a $4.1 million increase in depreciation and amortization expense related to our South Carolina synthetic fuel facility during the six months ended June 30, 2005 compared to the same period of 2004.

Accretion of Asset Retirement Obligations

Merchant energy accretion expense increased $2.9 million during the quarter ended June 30, 2005 compared to the same period of 2004 mostly due to the recognition of $2.1 million at Ginna.

Merchant energy accretion expenses increased $6.9 million during the six months ended June 30, 2005 compared to the same period of 2004 mostly due to the recognition of $5.1 million at Ginna.

Taxes Other Than Income Taxes

Merchant energy taxes other than income taxes increased $5.1 million during the quarter ended June 30, 2005 compared to the same period of 2004 mostly due to $2.1 million related to higher gross receipts taxes at our retail electric operation and $1.8 million related to property taxes for Ginna.

Taxes other than income taxes increased $8.7 million during the six months ended June 30, 2005 compared to the same period of 2004 mostly due to $3.8 million related to higher gross receipts taxes at our retail electric operation and $3.5 million related to property taxes for Ginna.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section of our 2004 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
		(In millions)		
Revenues	**$ 465.1**	$ 477.2	**$ 956.6**	$ 961.6
Electricity purchased for resale expenses	**(244.4)**	(254.3)	**(486.5)**	(494.7)
Operations and maintenance expenses	**(79.9)**	(78.5)	**(155.8)**	(145.4)
Depreciation and amortization	**(46.8)**	(48.5)	**(94.2)**	(96.3)
Taxes other than income taxes	**(33.1)**	(32.9)	**(67.5)**	(66.4)
Income from Operations	**$ 60.9**	$ 63.0	**$ 152.6**	$ 158.8
Net Income	**$ 25.4**	$ 25.2	**$ 68.9**	$ 70.3

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

Electric Revenues

The changes in electric revenues in 2005 compared to 2004 were caused by:

	Quarter Ended June 30, 2005 vs. 2004	Six Months Ended June 30, 2005 vs. 2004
	(In millions)	
Distribution volumes	$ (7.1)	$ (6.3)
Standard offer service	(5.9)	0.7
Total change in electric revenues from electric system sales	(13.0)	(5.6)
Other	0.9	0.6
Total change in electric revenues	$ (12.1)	$ (5.0)

Distribution Volumes

Distribution volumes are sales to all customers in BGE's service territory for the delivery service BGE provides at rates set by the Maryland PSC.

The percentage changes in our distribution volumes, by type of customer, in 2005 compared to 2004 were:

	Quarter Ended June 30, 2005 vs. 2004	Six Months Ended June 30, 2005 vs. 2004
Residential	(6.7)%	(3.9)%
Commercial	1.7	3.9
Industrial	(12.2)	(13.1)

During the quarter and six months ended June 30, 2005 compared to the same periods of 2004, we distributed less electricity to residential customers mostly due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed more electricity to commercial customers mostly due to increased usage per customer and an increased number of customers, partially offset by milder weather. We distributed less electricity to industrial customers mostly due to decreased usage per customer.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier as discussed in *Item 1. Business Electric Regulatory Matters and Competition* section of our 2004 Annual Report on Form 10-K.

Standard offer service revenues decreased during the quarter ended June 30, 2005 compared to the same period of 2004 mostly due to commercial and industrial customers that elected alternative suppliers beginning July 1, 2004 and milder weather. These decreased revenues were partially offset by increased standard offer service rates.

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.

Electricity purchased for resale expenses decreased $9.9 million in the quarter and $8.2 million in the six month periods ended June 30, 2005 compared to the same periods of 2004 mostly because commercial and industrial customers left BGE's standard offer service beginning July 1, 2004.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $1.4 million in the quarter and $10.4 million in the six months ended June 30, 2005 compared to the same periods of 2004 mostly due to higher compensation and benefit costs and the impact of inflation on other costs.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section of our 2004 Annual Report on Form 10-K.

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
	(In millions)			
Gas revenues	**$ 145.2**	$ 112.6	**$ 511.0**	$ 432.1
Gas purchased for resale expenses	**(90.1)**	(59.5)	**(350.4)**	(275.5)
Operations and maintenance expenses	**(32.1)**	(30.7)	**(64.0)**	(59.0)
Depreciation and amortization	**(11.6)**	(12.2)	**(23.8)**	(24.3)

	Quarter Ended June 30,				Six Months Ended June 30,			
Taxes other than income taxes		**(7.9)**		(7.6)		**(17.3)**		(16.7)
Income from operations	**$**	**3.5**	$	2.6	**$**	**55.5**	$	56.6
Net (Loss) Income	**$**	**(1.7)**	$	(3.3)	**$**	**25.9**	$	24.5

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

Gas Revenues

The changes in gas revenues in 2005 compared to 2004 were caused by:

	Quarter Ended June 30, 2005 vs. 2004		Six Months Ended June 30, 2005 vs. 2004	
	(In millions)			
Distribution volumes	$	2.3	$	(1.5)
Base rates				0.1
Weather normalization		(0.3)		5.4
Gas cost adjustments		11.4		18.9
Total change in gas revenues from gas system sales		13.4		22.9
Off-system sales		19.1		56.0
Other		0.1		
Total change in gas revenues	$	32.6	$	78.9

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2005 compared to 2004 were:

	Quarter Ended June 30, 2005 vs. 2004	Six Months Ended June 30, 2005 vs. 2004
Residential	9.4%	(3.7)%
Commercial	(14.0)	(4.5)
Industrial	37.6	14.4

During the quarter ended June 30, 2005 compared to the same period in 2004, we distributed more gas to residential customers mostly due to cooler weather and an increased number of customers, partially offset by decreased usage per customer. We distributed less gas to commercial customers mostly due to decreased usage per customer partially offset by cooler weather and an increased number of customers. We distributed more gas to industrial customers mostly due to increased usage per customer and an increased number of customers.

During the six months ended June 30, 2005 compared to the same period of 2004, we distributed less gas to residential and commercial customers mostly due to decreased usage per customer partially offset by an increased number of customers and colder weather. We distributed more gas to industrial customers mostly due to increased usage per customer.

Base Rates

On April 29, 2005, BGE filed an application for a $52.7 million annual increase in our gas base rates. The Maryland PSC is currently reviewing our application and is expected to issue an order by late December 2005. We cannot provide assurance that the Maryland PSC will approve the rate increase request, or if it does, that it will grant BGE the full amount requested.

Weather Normalization

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 2004 Annual Report on Form 10-K.

Gas cost adjustment revenues increased during the quarter ended June 30, 2005 compared to the same period of 2004 because we sold more gas at higher prices.

Gas cost adjustment revenues increased during the six months ended June 30, 2005 compared to the same period of 2004 because we sold gas at higher prices, partially offset by less gas sold.

Off-System Gas Sales

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

Revenues from off-system gas sales increased during the quarter and six months ended June 30, 2005 compared to the same periods of 2004 because we sold more gas at higher 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 during the quarter and six months ended June 30, 2005 compared to the same periods of 2004 because we purchased more gas at a higher price.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased $1.4 million in the quarter and $5.0 million in the six months ended June 30, 2005 compared to the same periods of 2004 mostly due to higher compensation and benefit costs and the impact of inflation on other costs.

Other Nonregulated Businesses

Results

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Revenues	**$ 116.9**	$ 103.3	**$ 223.2**	$ 208.5
Operating expense	**(91.4)**	(84.5)	**(177.0)**	(171.3)
Depreciation and amortization	**(12.7)**	(8.1)	**(23.9)**	(15.5)
Taxes other than income taxes	**(0.6)**	(0.7)	**(0.8)**	(1.2)
Income from Operations	**$ 12.2**	$ 10.0	**$ 21.5**	$ 20.5
Net Income (Loss)	**$ 2.6**	$ (0.2)	**$ 3.3**	$ (0.1)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 15 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

As previously discussed in our 2004 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 losses.

Consolidated Nonoperating Income and Expenses

Other Income

Other income increased $6.3 million during the quarter ended June 30, 2005, and $12.0 million during the six months ended June 30, 2005 compared to the same periods of 2004 primarily because of higher interest and investment income due to a higher cash balance and higher decommissioning earnings.

Fixed Charges

Total fixed charges decreased $6.2 million during the quarter ended June 30, 2005 and $10.1 million during the six months ended June 30, 2005 compared to the same periods of 2004 mostly because of the benefit of lower interest rates due to interest rate swaps entered into during the third quarter of 2004 and a lower level of debt outstanding. We discuss the interest rate swaps in more detail in the *Notes to Consolidated Financial Statements* beginning on page 22.

During the six months ended June 30, 2005, total fixed charges at BGE decreased $2.7 million compared to the same period of 2004 mostly because of a lower level of debt outstanding.

Income Taxes

During the quarter and six months ended June 30, 2005, our income taxes increased compared to the same periods of 2004 mostly because of the recognition of $35.9 million synthetic fuel tax credits claimed in 2004 related to 2003 production and an increase in taxable income. We discuss our synthetic fuel tax credits in more detail in the *Notes to Consolidated Financial Statements* section on page 17.

Financial Condition

Cash Flows

The following table summarizes our cash flows for 2005 and 2004, excluding the impact of changes in intercompany balances.

	2005 Segment Cash Flows Six Months Ended June 30, 2005			Consolidated Cash Flows Six Months Ended June 30,	
	Merchant	Regulated	Other	2005	2004
			(In millions)		
Operating Activities					
Net income	$ 144.3	$ 94.8	$ 3.3	$ 242.4	$ 194.4
Non-cash adjustments to net income	207.5	117.8	32.7	358.0	458.7
Changes in working capital	(163.5)	71.5	(13.9)	(105.9)	51.3
Pension and postemployment benefits*				(21.5)	(22.4)
Other	(17.8)	0.4	23.2	5.8	(20.7)
Net cash provided by operating activities	170.5	284.5	45.3	478.8	661.3
Investing activities					
Investments in property, plant and equipment	(159.8)	(127.9)	(16.0)	(303.7)	(322.0)
Asset acquisitions and business combinations, net of cash acquired	(215.8)		(22.1)	(237.9)	(430.0)
Contributions to nuclear decommissioning trust funds	(8.8)			(8.8)	(13.2)
Proceeds from sale of discontinued operations	217.6			217.6	72.7
Sale of investments and other assets			1.1	1.1	14.1
Issuances of loans receivable	(82.8)			(82.8)	
Other investments	(18.5)	(11.7)	4.2	(26.0)	(10.1)
Net cash used in investing activities	(268.1)	(139.6)	(32.8)	(440.5)	(688.5)
Cash flows from operating activities less cash flows from investing activities	$ (97.6)	$ 144.9	$ 12.5	38.3	(27.2)
Financing Activities*					
Net repayment of debt				(326.3)	(177.5)
Proceeds from issuance of common stock				45.2	30.5
Common stock dividends paid				(109.6)	(91.4)
Proceeds from acquired contracts				381.5	
Other				(10.8)	1.3
Net cash used in financing activities				(20.0)	(237.1)
Net Increase (Decrease) in Cash and Cash Equivalents				$ 18.3	$ (264.3)

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

Cash Flows from Operating Activities

Cash provided by operating activities was $478.8 million in 2005 compared to $661.3 million in 2004. Net income was $48.0 million higher in 2005 compared to 2004. This was partially offset by a decrease in non-cash adjustments to net income of $100.7 million in 2005 compared to 2004 primarily due to a decrease in loss from discontinued operations. Changes in working capital had a negative impact of $105.9 million on cash flow from operations in 2005 compared to a positive impact of $51.3 million in 2004. The net decrease of $157.2 million was primarily due to:

an increase of $108.2 million in cash used for fuel stocks and other working capital requirements mostly due to increased international coal and domestic gas activities at our wholesale marketing and risk management operation, and

a decrease of $34.9 million in cash from customer deposits mostly due to changes in collateral requirements posted from counterparties in 2005 compared to 2004.

Cash Flows from Investing Activities

Cash used in investing activities was $440.5 million in 2005 compared to $688.5 million in 2004. The decrease in cash used in 2005 compared to 2004 was primarily due to less cash paid for asset acquisitions and business combinations of $192.1 million in 2005 compared to 2004, and an increase in cash proceeds from the sale of discontinued operations of $144.9 million, primarily due to the sale of Oleander in 2005 for $217.6 million. Included in investing activities in 2005, is approximately $211 million for investments in gas properties as discussed in more detail in the *Notes to the Consolidated Financial Statements* on page 14. This decrease in cash used in investing activities was partially offset by an increase of $82.8 million in issuances of loans receivable related to a customer contract restructuring which is discussed in more detail in the *Notes to the Consolidated Financial Statements* beginning on page 11.

Cash Flows from Financing Activities

Cash used in financing activities was $20.0 million in 2005 compared to $237.1 million in 2004. The decrease in cash used in 2005 compared to 2004 was mostly due to proceeds from acquired contracts of $381.5 million during 2005 associated with power purchase agreements entered into by our merchant energy business. We discuss cash flows from customer contract restructurings in more detail in the *Notes to the Consolidated Financial Statements* beginning on page 11. This decrease in cash used in financing activities was partially offset by an increase in cash used for repayments of long-term debt, higher dividend payments, and an increase in cash paid for other financing activities in 2005 compared to 2004.

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

In addition to our cash balance, we have a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At June 30, 2005, we had approximately $2.6 billion of credit under three facilities. These facilities include:

- an $800.0 million three-year revolving credit facility that expires in June 2007,
- a $300.0 million five-year revolving credit facility that expires in June 2009, and
- a $1.5 billion five-year revolving credit facility that expires in June 2010.

We use these facilities to ensure adequate liquidity to support our operations. Currently, we use these facilities to support letters of credit primarily for our merchant energy business. Additionally, we can borrow directly from the banks or use the facilities to allow the issuance of commercial paper.

These revolving credit facilities allow the issuance of letters of credit up to approximately $2.6 billion. At June 30, 2005, letters of credit that totaled $958.7 million were issued under all of our facilities, which results in approximately $1.6 billion of unused credit facilities.

BGE

BGE maintains $200.0 million in annual committed credit facilities, expiring August 2005 through June 2006, in order to allow commercial paper to be issued. BGE can borrow directly from the banks or use the facilities to allow commercial paper to be issued. As of June 30, 2005, BGE had no outstanding commercial paper, which results in $200.0 million in unused credit facilities.

Capital Resources

Our estimated annual amounts for the years 2005 and 2006 are shown in the table below.

We will continue to have cash requirements for:

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

Capital requirements for 2005 and 2006 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

regulation, legislation, and competition,

BGE load requirements,

environmental protection standards,

the type and number of projects selected for construction or acquisition,

the effect of 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 50. We discuss the potential impact of environmental legislation in more detail in *Item 1. Business Environmental Matters* section of our 2004 Annual Report on Form 10-K. We discuss regulations recently adopted by the EPA and their impact on our capital requirements in the *Environmental Matters* section on page 27.

Calendar Year Estimates	**2005**	**2006**
	(In millions)	
Nonregulated Capital Requirements:		
Merchant energy		
Generation plants	$ 175	$ 175
Nuclear fuel	125	120
Environmental controls	5	45
Portfolio acquisitions/investments	250	155
Technology/other	155	115
Total merchant energy capital requirements	710	610
Other nonregulated capital requirements	35	5
Total nonregulated capital requirements	745	615
Regulated Capital Requirements:		
Regulated electric	250	280
Regulated gas	55	50
Total regulated capital requirements	305	330
Total capital requirements	$ 1,050	$ 945

The above amounts do not include the Cogenex business combination. We discuss the acquisition of Cogenex in more detail in the Notes to Consolidated Financial Statements on page 14.

Our 2005 capital requirements increased since March 31, 2005 primarily due to approximately $211 million of investments made in gas properties during the second quarter of 2005. We discuss these investments in more detail in the *Notes to the Consolidated Financial Statements* on page 14.

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,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions regulations, and
- portfolio acquisitions, upstream gas investments, and other investments,
- 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.

Funding for Capital Requirements

We discuss our funding for capital requirements in our 2004 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.

Our total contractual payment obligations as of June 30, 2005, increased $446.5 million during the first six months of 2005 primarily due to new contracts related to nuclear fuel and coal procurement. We detail our contractual payment obligations in the following table:

	Payments				
	2005	2006-2007	2008-2009	There-after	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 13.2	$ 647.5	$ 520.6	$ 2,333.4	$ 3,514.7
Interest	106.2	395.1	335.0	1,612.5	2,448.8
Total	119.4	1,042.6	855.6	3,945.9	5,963.5

	Payments				
BGE					
Principal	21.5	565.4	307.5	589.2	1,483.6
Interest	43.7	138.7	78.3	806.6	1,067.3
Total	65.2	704.1	385.8	1,395.8	2,550.9
BGE preference stock				190.0	190.0
Operating leases[2]	72.1	277.1	134.7	359.9	843.8
Purchase obligations:[3]					
Purchased capacity and energy[4]	402.6	813.9	478.4	183.4	1,878.3
Fuel and transportation	944.1	1,516.1	271.2	145.9	2,877.3
Other	75.7	111.7	65.8	177.9	431.1
Other noncurrent liabilities:					
Postretirement and postemployment benefits[5]	19.7	74.0	79.9	204.2	377.8
Other	1.6				1.6
Total contractual payment obligations	$ 1,700.4	$ 4,539.5	$ 2,271.4	$ 6,603.0	$ 15,114.3

1 Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $381.6 million early through put options and remarketing features. Interest on variable rate debt is included based on the June 30, 2005 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 2004 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. We have recorded $9.4 million of liabilities related to purchased capacity and energy obligations at June 30, 2005 in our Consolidated Balance Sheets.

5 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 on the Consolidated Balance Sheets.

The table on the next page presents our contingent obligations. Our contingent obligations increased $1,130.8 million during the first half of 2005, primarily due to additional letters of credit and guarantees by the parent company for subsidiary obligations to third parties in support of the growth of our merchant energy business. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties. Our calculation of the fair value of subsidiary obligations covered by the $6,482.8 million of parent company guarantees was

$2,152.7 million at June 30, 2005. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount based on June 30, 2005 market prices would be $2,152.7 million.

	Expiration				
	2005	2006-2007	2008-2009	There-after	Total
			(In millions)		
Contingent Obligations					
Letters of credit	$ 786.8	$ 171.9	$	$	$ 958.7
Guarantees competitive supply[1]	3,070.5	1,813.4	306.3	1,292.6	6,482.8
Other guarantees, net[2]	0.4	5.6	15.4	1,244.0	1,265.4
Total contingent obligations	$ 3,857.7	$ 1,990.9	$ 321.7	$ 2,536.6	$ 8,706.9

1 While the face amount of these guarantees is $6,482.8 million, we do not expect to fund the full amount. In the event the parent were required to fulfill subsidiary obligations, our calculation of the fair value of obligations covered by these guarantees was $2,152.7 million at June 30, 2005.

2 Other guarantees in the above table are shown net of liabilities of $25.0 million recorded at June 30, 2005 in our Consolidated Balance Sheets.

Liquidity Provisions

In many cases, customers of our wholesale marketing and risk management 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 wholesale marketing and risk management operation and our retail competitive supply activities.

We have certain agreements that contain provisions that would require additional collateral upon significant credit rating decreases in the 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 and risk management operation, we are obligated to post collateral if Constellation Energy's senior, unsecured credit ratings decline below established contractual levels. Based on contractual provisions, we estimate that we would have additional collateral obligations based on downgrades to the following credit ratings for our Senior Unsecured Debt:

Credit Ratings Downgraded to	Incremental Obligations	Cumulative Obligations
	(In millions)	
BBB-/Baa3	$ 282	$ 282
Below investment grade	804	1,086

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. At June 30, 2005, we had approximately $1.6 billion of unused credit facilities.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2005, the debt to capitalization ratio as defined in the credit agreements was no greater than

53%. Certain credit facilities of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At June 30, 2005, the debt to capitalization ratio for BGE as defined in these credit agreements was 45%. At June 30, 2005, no amount is outstanding under these facilities.

Off-Balance Sheet Arrangements

We discuss our off-balance sheet arrangements in our 2004 Annual Report on Form 10-K.

Market Risk

Commodity Risk

We measure the sensitivity of our wholesale marketing and risk management 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 and risk management 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 2004 Annual Report on Form 10-K. The table below is the value at risk associated with our wholesale marketing and risk management operation's mark-to-market energy assets and liabilities, including both trading and non-trading activities.

		Six Months Ended June 30, 2005
		(In millions)
99% Confidence Level, One-Day Holding Period		
Average	$	3.6
High		6.0
95% Confidence Level, One-Day Holding Period		
Average		2.7
High		4.6
95% Confidence Level, Ten-Day Holding Period		
Average		8.7
High		14.5

The following table details our value at risk for the trading portion of our wholesale marketing and risk management mark-to-market energy assets and liabilities over a one-day holding period at a 99% confidence level for the first six months of 2005:

	Six Months Ended June 30, 2005
	(In millions)
Average	$ 3.1
High	6.3

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 manage the credit portfolio of our wholesale marketing and risk management operation to attempt to reduce the impact of counterparty default. As of June 30, 2005 and December 31, 2004, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings:

	June 30, 2005	December 31, 2004
Rating		
Investment Grade[1]	**69%**	62%
Non-Investment Grade	**15**	15
Not Rated	**16**	23

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.

Compared to December 31, 2004, we experienced an improvement in the credit quality of our publicly rated wholesale marketing and risk management portfolio. The improvement in investment grade equivalent counterparties reflects reduced exposure to below investment grade coal suppliers and to a below investment grade energy company, and the stabilizing trend in the credit quality of energy companies. Our exposure to the below investment grade energy company decreased due to the execution of a master netting agreement. The agreement allows amounts payable between parties to be offset, resulting in a lower net exposure.

In addition to the credit ratings provided by the major credit rating agencies, 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.

	June 30, 2005	December 31, 2004
Investment Grade Equivalent	**82%**	74%
Non-Investment Grade	**18**	26

Compared to December 31, 2004, the credit quality of our wholesale marketing and risk management portfolio has improved. The improvement reflects reduced exposure to below investment grade coal suppliers and to a below investment grade energy company, and the stabilizing trend in the credit quality of energy companies. 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 and risk management 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 following table highlights the credit quality and exposures related to these activities at June 30, 2005:

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	$ 1,068	$ 101	$ 967	1	$ 202
Split rating	18		18		
Non-investment grade	248	5	243		
Internally rated investment grade	135	3	132		
Internally rated non-investment grade	2		2		
Total	$ 1,471	$ 109	$ 1,362	1	$ 202

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 and risk management 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 45.

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 2004 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 section in the *Notes to Consolidated Financial Statements* beginning on page 22,

activities of our wholesale marketing and risk management operation in the *Merchant Energy Business* section of *Management's Discussion and Analysis* beginning on page 30,

evaluation of commodity and credit risk in the *Market Risk* section of *Management's Discussion and Analysis* beginning on page 45, 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, in that they provide reasonable assurance that such officers are alerted on a timely basis to material information relating to Constellation Energy and BGE that is required to be included in Constellation Energy's and BGE's periodic filings under the Exchange Act.

Changes in Internal Control over Financial Reporting

Except as discussed below, during the quarter ended June 30, 2005, 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.

During the second quarter of 2005, our wholesale marketing and risk management operation implemented new back office accounting and settlement systems. The implementation required revisions to our internal controls over financial reporting. We reviewed the systems during and following the implementation, as well as the controls affected by the implementation of the systems and made appropriate changes to affected internal controls.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 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.

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
April 1 April 30, 2005	997	$ 51.76		
May 1 May 31, 2005	47,963	52.19		
June 1 June 30, 2005	79,278	53.11		
Total	128,238	$ 52.75		

Item 4. Submission of Matters to a Vote of Security Holders

On May 20, 2005, we held our annual meeting of shareholders. At that meeting, the following matters were voted upon:

1. All of the Directors nominated by Constellation Energy Group were elected as follows:

	COMMON SHARES CAST:		
	For	Against	Abstain
Yves C. de Balmann	150,511,950	2,247,150	1
Freeman A. Hrabowski, III	149,141,815	3,617,285	1
Nancy Lampton	150,691,488	2,067,612	1
Lynn M. Martin	149,080,974	3,678,126	1

All other directors whose term of office continued after the date of this meeting are:

Douglas L. Becker
Frank P. Bramble
James T. Brady
Edward C. Crooke
James R. Curtiss
Edward J. Kelly, III
Robert J. Lawless
Mayo A. Shattuck III
Michael D. Sullivan

2. The ratification of PricewaterhouseCoopers LLP as independent auditors was approved. With respect to holders of common stock, the number of affirmative votes cast was 148,310,541, the number of votes cast against was 3,110,719, and the number of abstentions was 1,337,834.

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 on a transitional basis in those markets,
- uncertainties associated with estimating natural gas reserves, developing properties, and extracting natural gas,
- regulatory or legislative developments that affect deregulation, 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 inability of Baltimore Gas and Electric Company (BGE) to recover all its costs associated with providing electric residential customers service during the electric rate freeze period,
- the conditions of the capital markets, interest rates, availability of credit, liquidity, 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, 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. 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 18 U.S.C. Section 1350, as adopted 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 Administrative Officer of Constellation Energy Group, Inc. pursuant to 18 U.S.C. Section 1350, as adopted 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 18 U.S.C. Section 1350, as adopted 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 18 U.S.C. Section 1350, as adopted 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 Administrative 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.

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: August 8, 2005

/s/ E. FOLLIN SMITH

E. Follin Smith,
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

QuickLinks