CONSTELLATION ENERGY GROUP INC
Form 10-Q
May 09, 2006

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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 **March 31, 2006**

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

MARYLAND
(State of Incorporation of both registrants)

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

410-783-2800

(Registrants' telephone number, including area code)

NOT APPLICABLE

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days. Yes ý No o

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

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

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

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

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

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

Common Stock, without par value 178,948,857 shares outstanding of Constellation Energy Group, Inc. on April 28, 2006.

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

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PART 1 FINANCIAL INFORMATION

Item 1 Financial Statements

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

	Three Months Ended March 31, 2006	2005
	(In millions, except per share amounts)	
Revenues		
Nonregulated revenues	**$ 3,975.2**	$ 2,715.9
Regulated electric revenues	**504.0**	491.5
Regulated gas revenues	**418.3**	364.6
Total revenues	**4,897.5**	3,572.0
Expenses		
Fuel and purchased energy expenses	**3,924.2**	2,677.6
Operating expenses	**521.0**	458.3
Workforce reduction costs	**2.2**	
Merger-related costs	**1.9**	
Depreciation, depletion, and amortization	**134.3**	130.6
Accretion of asset retirement obligations	**16.5**	15.1
Taxes other than income taxes	**74.9**	68.5
Total expenses	**4,675.0**	3,350.1
Income from Operations	**222.5**	221.9
Other Income	**14.2**	12.9
Fixed Charges		
Interest expense	**77.0**	79.7
Interest capitalized and allowance for borrowed funds used during construction	**(2.8)**	(2.9)
BGE preference stock dividends	**3.3**	3.3
Total fixed charges	**77.5**	80.1
Income from Continuing Operations Before Income Taxes	**159.2**	154.7
Income Tax Expense	**46.2**	36.1
Income from Continuing Operations	**113.0**	118.6
Income from discontinued operations, net of income taxes of $0.5 and $3.3, respectively	**0.9**	2.1
Net Income	**$ 113.9**	$ 120.7
Earnings Applicable to Common Stock	**$ 113.9**	$ 120.7
Average Shares of Common Stock Outstanding Basic	**178.6**	176.8

		Three Months Ended March 31,		
Average Shares of Common Stock Outstanding Diluted		**180.4**		178.6
Earnings Per Common Share from Continuing Operations Basic	**$**	**0.63**	$	0.67
Income from discontinued operations		**0.01**		0.01
Earnings Per Common Share Basic	**$**	**0.64**	$	0.68
Earnings Per Common Share from Continuing Operations Diluted	**$**	**0.63**	$	0.67
Income from discontinued operations				0.01
Earnings Per Common Share Diluted	**$**	**0.63**	$	0.68
Dividends Declared Per Common Share	**$**	**0.3775**	$	0.335

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

		Three Months Ended March 31,		
		2006		**2005**
		(In millions)		
Net Income	**$**	**113.9**	$	120.7
Other comprehensive income (OCI)				
Reclassification of net gain on sales of securities from OCI to net income, net of taxes		**(0.3)**		(0.1)
Reclassification of net loss (gain) on hedging instruments from OCI to net income, net of taxes		**81.0**		(37.6)
Net unrealized (loss) gain on hedging instruments, net of taxes		**(755.0)**		218.5
Net unrealized gain on securities, net of taxes		**11.8**		10.9
Net unrealized loss on foreign currency, net of taxes				(0.1)
Comprehensive Income	**$**	**(548.6)**	$	312.3

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

	March 31, 2006*	December 31, 2005
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 424.8**	$ 813.0
Accounts receivable (net of allowance for uncollectibles of **$51.6** and $47.4, respectively)	**2,657.5**	2,727.9
Fuel stocks	**427.8**	489.5
Materials and supplies	**195.3**	197.0
Mark-to-market energy assets	**938.4**	1,339.2
Risk management assets	**438.9**	1,244.3
Unamortized energy contract assets	**50.6**	55.6
Deferred income taxes	**193.6**	
Other	**640.3**	555.3
Total current assets	**5,967.2**	7,421.8
Investments and Other Assets		
Nuclear decommissioning trust funds	**1,140.5**	1,110.7
Investments in qualifying facilities and power projects	**307.9**	306.2
Regulatory assets (net)	**121.9**	154.3
Goodwill	**146.5**	147.1
Mark-to-market energy assets	**858.5**	1,089.3
Risk management assets	**459.8**	626.0
Unamortized energy contract assets	**144.8**	141.2
Other	**367.1**	410.6
Total investments and other assets	**3,547.0**	3,985.4
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**8,766.2**	8,580.8
Regulated property, plant and equipment	**5,573.0**	5,520.5
Nuclear fuel (net of amortization)	**295.5**	302.0
Accumulated depreciation	**(4,419.3)**	(4,336.6)
Net property, plant and equipment	**10,215.4**	10,066.7
Total Assets	**$ 19,729.6**	$ 21,473.9

** Unaudited*

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	March 31, **2006***	*December 31,* **2005**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 425.0**	$ 0.7
Current portion of long-term debt	**612.8**	491.3
Accounts payable and accrued liabilities	**1,657.6**	1,667.9
Customer deposits and collateral	**304.7**	458.9
Mark-to-market energy liabilities	**801.4**	1,348.7
Risk management liabilities	**654.2**	483.5
Unamortized energy contract liabilities	**459.6**	489.5
Deferred income taxes		151.4
Accrued expenses and other	**537.1**	780.4
Total current liabilities	**5,452.4**	5,872.3
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,064.2**	1,180.8
Asset retirement obligations	**924.7**	908.0
Mark-to-market energy liabilities	**635.9**	912.3
Risk management liabilities	**968.6**	1,035.5
Unamortized energy contract liabilities	**997.4**	1,118.7
Postretirement and postemployment benefits	**384.2**	382.6
Net pension liability	**368.5**	401.4
Deferred investment tax credits	**62.3**	64.1
Other	**108.4**	101.0
Total deferred credits and other liabilities	**5,514.2**	6,104.4
Long-term Debt		
Long-term debt of Constellation Energy	**3,043.5**	3,049.1
Long-term debt of nonregulated businesses	**341.7**	357.5
First refunding mortgage bonds of BGE	**342.8**	342.8
Other long-term debt of BGE	**861.5**	861.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(7.6)**	(8.0)
Current portion of long-term debt	**(612.8)**	(491.3)
Total long-term debt	**4,226.8**	4,369.3
Minority Interests	**22.2**	22.4
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock	**2,645.5**	2,620.8

		March 31, 2006*		December 31, 2005
Retained earnings		**2,856.5**		2,810.2
Accumulated other comprehensive loss		**(1,178.0)**		(515.5)
Total common shareholders' equity		**4,324.0**		4,915.5
Commitments, Guarantees, and Contingencies (see Notes)				
Total Liabilities and Equity	**$**	**19,729.6**	$	21,473.9

** Unaudited*

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,	2006	2005
	(In millions)	
Cash Flows From Operating Activities		
Net income	$ **113.9**	$ 120.7
Adjustments to reconcile to net cash (used in) provided by operating activities		
(Gain) loss from discontinued operations	**(0.9)**	3.0
Depreciation, depletion, and amortization	**143.9**	161.8
Accretion of asset retirement obligations	**16.5**	15.1
Deferred income taxes	**(48.3)**	21.6
Investment tax credit adjustments	**(1.7)**	(1.8)
Deferred fuel costs	**7.1**	3.6
Pension and postemployment benefits	**(30.5)**	(33.4)
Workforce reduction costs	**2.2**	
Merger-related costs	**1.9**	
Equity in earnings of affiliates less than dividends received	**5.0**	7.5
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149	**(19.6)**	
Changes in		
Accounts receivable	**(76.1)**	15.8
Mark-to-market energy assets and liabilities	**(191.0)**	(21.2)
Risk management assets and liabilities		(56.3)
Materials, supplies, and fuel stocks	**(73.8)**	11.2
Other current assets	**(64.0)**	6.7
Accounts payable and accrued liabilities	**(23.3)**	32.3
Other current liabilities	**(269.6)**	62.9
Other	**19.1**	0.1
Net cash (used in) provided by operating activities	**(489.2)**	349.6
Cash Flows From Investing Activities		
Investments in property, plant and equipment	**(184.4)**	(143.8)
Asset acquisitions and business combinations, net of cash acquired	**(100.8)**	(3.5)
Investments in nuclear decommissioning trust fund securities	**(57.7)**	(64.0)
Proceeds from nuclear decommissioning trust fund securities	**53.3**	59.6
Sales of investments and other assets	**14.6**	0.3
Issuances of loans receivable		(176.4)
Other investments	**(10.6)**	35.3
Net cash used in investing activities	**(285.6)**	(292.5)
Cash Flows From Financing Activities		
Net issuance of short-term borrowings	**424.3**	3.0
Proceeds from issuance of common stock	**18.8**	26.3
Repayment of long-term debt	**(17.6)**	(22.7)
Common stock dividends paid	**(59.8)**	(50.2)
Proceeds from contract and portfolio acquisitions		308.5
Proceeds from derivative power sales contracts classified as financing activities under SFAS No. 149	**19.6**	
Other	**1.3**	(25.4)

Three Months Ended March 31,	2006	2005
Net cash provided by financing activities	**386.6**	239.5
Net (Decrease) Increase in Cash and Cash Equivalents	**(388.2)**	296.6
Cash and Cash Equivalents at Beginning of Period	**813.0**	706.3
Cash and Cash Equivalents at End of Period	**$ 424.8**	$ 1,002.9

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 March 31, 2006	2005
	(In millions)	
Revenues		
Electric revenues	**$ 504.0**	$ 491.5
Gas revenues	**420.2**	365.8
Total revenues	**924.2**	857.3
Expenses		
Operating expenses		
Electricity purchased for resale	**262.9**	242.1
Gas purchased for resale	**298.4**	260.3
Operations and maintenance	**120.0**	107.8
Merger-related costs	**0.6**	
Depreciation and amortization	**57.7**	59.6
Taxes other than income taxes	**43.5**	43.8
Total expenses	**783.1**	713.6
Income from Operations	**141.1**	143.7
Other Income	**0.1**	1.0
Fixed Charges		
Interest expense	**24.2**	23.7
Allowance for borrowed funds used during construction	**(0.4)**	(0.4)
Total fixed charges	**23.8**	23.3
Income Before Income Taxes	**117.4**	121.4
Income Taxes	**45.7**	47.1
Net Income	**71.7**	74.3
Preference Stock Dividends	**3.3**	3.3
Earnings Applicable to Common Stock	**$ 68.4**	$ 71.0

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, **2006***		*December 31,* **2005**	
		(In millions)		
Assets				
Current Assets				
Cash and cash equivalents	**$**	**14.3**	$	15.1
Accounts receivable (net of allowance for uncollectibles of **$13.6** and $13.0, respectively)		**453.3**		480.5
Investment in cash pool, affiliated company		**91.7**		
Accounts receivable, affiliated companies		**0.6**		1.8
Fuel stocks		**48.4**		102.7
Materials and supplies		**37.6**		40.1
Prepaid taxes other than income taxes		**22.8**		45.7
Other		**9.8**		6.5
Total current assets		**678.5**		692.4
Investments and Other Assets				
Regulatory assets (net)		**121.9**		154.3
Receivable, affiliated company		**179.2**		154.7
Other		**124.7**		144.0
Total investments and other assets		**425.8**		453.0
Utility Plant				
Plant in service				
Electric		**3,917.4**		3,891.1
Gas		**1,122.5**		1,116.7
Common		**432.7**		416.0
Total plant in service		**5,472.6**		5,423.8
Accumulated depreciation		**(1,942.4)**		(1,923.8)
Net plant in service		**3,530.2**		3,500.0
Construction work in progress		**97.6**		93.9
Plant held for future use		**2.8**		2.8
Net utility plant		**3,630.6**		3,596.7
Total Assets	**$**	**4,734.9**	$	4,742.1

* *Unaudited*

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, 2006*	December 31, 2005
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	$ **591.5**	$ 469.6
Accounts payable and accrued liabilities	**124.2**	169.7
Accounts payable and accrued liabilities, affiliated companies	**148.2**	152.8
Borrowing from cash pool, affiliated company		3.2
Customer deposits	**69.2**	65.1
Accrued taxes	**83.7**	35.5
Accrued expenses and other	**78.6**	79.6
Total current liabilities	**1,095.4**	975.5
Deferred Credits and Other Liabilities		
Deferred income taxes	**599.4**	608.9
Postretirement and postemployment benefits	**276.7**	277.7
Deferred investment tax credits	**14.7**	15.1
Other	**16.1**	19.0
Total deferred credits and other liabilities	**906.9**	920.7
Long-term Debt		
First refunding mortgage bonds of BGE	**342.8**	342.8
Other long-term debt of BGE	**861.5**	861.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Long-term debt of nonregulated business	**25.0**	25.0
Unamortized discount and premium	**(2.2)**	(2.3)
Current portion of long-term debt	**(591.5)**	(469.6)
Total long-term debt	**893.3**	1,015.1
Minority Interest	**18.2**	18.3
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**718.2**	709.6
Accumulated other comprehensive income	**0.7**	0.7
Total common shareholder's equity	**1,631.1**	1,622.5

	March 31, 2006*		December 31, 2005	
Commitments, Guarantees, and Contingencies (see Notes)				
Total Liabilities and Equity	**$**	**4,734.9**	$	4,742.1

** Unaudited*

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Three Months Ended March 31,	**2006**	2005
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 71.7**	$ 74.3
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**60.3**	63.1
Deferred income taxes	**(10.1)**	(9.1)
Investment tax credit adjustments	**(0.4)**	(0.4)
Deferred fuel costs	**7.1**	3.6
Pension and postemployment benefits	**(24.7)**	(19.6)
Allowance for equity funds used during construction	**(0.8)**	(0.7)
Changes in		
Accounts receivable	**27.2**	(28.1)
Receivables, affiliated companies	**1.2**	(1.3)
Materials, supplies, and fuel stocks	**56.8**	75.6
Other current assets	**22.0**	23.9
Accounts payable and accrued liabilities	**(45.5)**	(25.6)
Accounts payable and accrued liabilities, affiliated companies	**(4.6)**	56.1
Other current liabilities	**51.3**	54.9
Other	**11.9**	6.1
Net cash provided by operating activities	**223.4**	272.8
Cash Flows From Investing Activities		
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(74.6)**	(58.1)
Change in cash pool at parent	**(94.9)**	(167.2)
Sales of investments and other assets	**0.5**	
Other	**7.9**	(20.4)
Net cash used in investing activities	**(161.1)**	(245.7)
Cash Flows From Financing Activities		
Distribution to parent	**(59.8)**	
Repayment of long-term debt		(20.0)
Preference stock dividends paid	**(3.3)**	(3.3)
Net cash used in financing activities	**(63.1)**	(23.3)
Net (Decrease) Increase in Cash and Cash Equivalents	**(0.8)**	3.8
Cash and Cash Equivalents at Beginning of Period	**15.1**	8.2
Cash and Cash Equivalents at End of Period	**$ 14.3**	$ 12.0

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 statement of the results of operations for the interim periods presented. These adjustments are of a normal recurring nature.

Basis of Presentation

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

Pending Merger with FPL Group, Inc.

On December 18, 2005, Constellation Energy entered into an Agreement and Plan of Merger with FPL Group, Inc. (FPL Group). We discuss the details of this pending merger in *Note 15* of our 2005 Annual Report on Form 10-K.

Prior to completion of the merger, which is subject to shareholder and various regulatory approvals, Constellation Energy and FPL Group will continue to operate as separate companies.

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 in *Note 4* to our 2005 Annual Report on Form 10-K.

The following is summary information available as of March 31, 2006 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	$ 830.6	$ 244.0	$ 1,074.6

	Power Contract Monetization VIEs	All Other VIEs	Total
Total liabilities	650.0	85.4	735.4
Our ownership interest		47.6	47.6
Other ownership interests	180.6	111.0	291.6
Our maximum exposure to loss	73.2	69.6	142.8

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 March 31, 2006 consists of the following:

- outstanding loans and letters of credit totaling $82.6 million,
- the carrying amount of our investment totaling $47.5 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.

Discontinued Operations

In the fourth quarter of 2005, we completed the sale of Constellation Power International Investments, Ltd. During the first quarter of 2006, we recognized an after-tax gain of $0.9 million due to the resolution of an outstanding contingency related to the sale. We discuss the details of the outstanding contingency in *Note 2* of our 2005 Annual Report on Form 10-K.

Workforce Reduction Costs

In March 2006, we approved a restructuring of the workforce at our R.E. Ginna Nuclear Power Plant (Ginna). In connection with this restructuring, 32 employees were terminated. During the quarter ended March 31, 2006, we recognized costs of $2.2 million pre-tax related to recording a liability for severance and other benefits under our existing benefit programs.

Merger-Related Costs

We continued to incur costs related to our pending merger with FPL Group, which totaled $1.9 million pre-tax for the quarter ended March 31, 2006. Through March 31, 2006, we have recognized $18.9 million pre-tax of merger costs. We anticipate our total merger-related costs to be approximately $55 million, excluding incremental expense associated with our equity awards that provide for accelerated vesting and cash settlement in the event of a change in control. We discuss the details of our pending merger in *Note 15* and our stock-based compensation plans in *Note 14* of our 2005 Annual Report on Form 10-K.

Earnings Per Share

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

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

	Quarter Ended March 31,	
	2006	**2005**
	(In millions)	
Non-dilutive stock options	**2.0**	0.7
Dilutive common stock equivalent shares	**1.8**	1.8

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance-based units, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors.

We adopted the provisions of Statement of Financial Accounting Standard (SFAS) No. 123 Revised (SFAS No. 123R), *Share-Based Payment*, on October 1, 2005, as described in more detail in *Note 1* of our 2005 Annual Report on From 10-K. Under SFAS No. 123R, we recognize compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award, which is typically a one to five-year period. We use a forfeiture assumption to estimate the number of awards that are expected to vest during the service period, and we ultimately true-up the estimated expense to the actual expense associated with vested awards. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option-pricing model, and we re-measure the fair value of liability awards each reporting period.

The following table illustrates the pro-forma effect on net income and earnings per share for all outstanding stock options and stock awards during the quarter ended March 31, 2005, when the fair value provisions of SFAS No. 123R were not in effect. We do not capitalize any portion of our stock-based compensation.

	Quarter Ended March 31, 2005
	(In millions, except per share amounts)

		Quarter Ended March 31, 2005
Net income, as reported	$	120.7
Add: Stock-based compensation expense determined under intrinsic value method and included in reported net income, net of related tax effects		4.5
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects		(6.6)
Pro-forma net income	$	118.6
Earnings per share:		
Basic as reported	$	0.68
Basic pro forma		0.67
Diluted as reported		0.68
Diluted pro forma		0.66

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. FASB Interpretation (FIN) 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143,* clarifies that obligations that are conditional upon a future event are subject to the provisions of SFAS No. 143.

We measure asset retirement obligations 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 2006 was as follows:

		(In millions)
Liability at January 1, 2006	$	908.0
Accretion expense		16.5
Other		
Liabilities incurred		0.2
Liabilities settled		
Revisions to cash flows		
Liability at March 31, 2006	$	924.7

"Liabilities incurred" in the table above primarily reflect asset retirement obligations recorded in connection with our investment in gas and oil producing properties discussed below.

Asset Acquisition

In the first quarter of 2006, we acquired working interests in gas and oil producing properties for approximately $100 million in cash. We purchased leases, producing wells, and related equipment. We accounted for the purchase as an asset acquisition and include the results of operations in our merchant energy business segment.

Business Combination

Cogenex

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 $34.9 million. We acquired cash of $14.4 million as part of the purchase.

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

At April 1, 2005

		(In millions)
Cash	$	14.4
Other Current Assets		12.4
Total Current Assets		26.8
Net Property, Plant and Equipment		
Other Assets		34.9
Total Assets Acquired		61.7
Current Liabilities		(8.0)
Deferred Credits and Other Liabilities		(18.8)

At April 1, 2005

Net Assets Acquired	$	34.9

We believe that the pro-forma impact of the Cogenex acquisition would not have been material to our results of operations in 2005.

Information by Operating Segment

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

Our merchant energy business is nonregulated and includes:

full requirements load-serving sales of energy and capacity to utilities and commercial, industrial, and governmental customers,

structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs and trading activities managed through daily value at risk and stop loss limits and liquidity guidelines),

gas retail energy products and services to commercial, industrial, and governmental customers,

fossil, nuclear, and interests in hydroelectric generating facilities and qualifying facilities, fuel processing facilities, and power projects in the United States,

products and services to upstream (exploration and production) and downstream (transportation and storage) wholesale natural gas customers,

coal sourcing services for the variable or fixed supply needs of North American and international power generators, and

generation operations and maintenance services.

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

Our regulated gas business purchases, transports, and sells natural gas in Central Maryland.

Our remaining nonregulated businesses:

design, construct, and operate heating, cooling, and cogeneration facilities for commercial, industrial, and municipal customers throughout North America, and

provide home improvements, service electric and gas appliances, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide natural gas marketing to residential customers in Central Maryland.

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

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

	Reportable Segments					
	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Eliminations	Consolidated
				(In millions)		
Quarter ended March 31,						
2006						
Unaffiliated revenues	**$ 3,914.4**	**$ 504.0**	**$ 418.3**	**$ 60.8**	**$**	**$ 4,897.5**
Intersegment revenues	**207.2**		**1.9**	**0.1**	**(209.2)**	
Total revenues	**4,121.6**	**504.0**	**420.2**	**60.9**	**(209.2)**	**4,897.5**
Income from discontinued operations				**0.9**		**0.9**
Net income	**43.6**	**33.6**	**35.0**	**1.7**		**113.9**
2005						
Unaffiliated revenues	$ 2,667.6	$ 491.5	$ 364.6	$ 48.3	$	$ 3,572.0
Intersegment revenues	225.5		1.2	0.2	(226.9)	
Total revenues	2,893.1	491.5	365.8	48.5	(226.9)	3,572.0
Income from discontinued operations	0.4			1.7		2.1
Net income	48.9	43.5	27.6	0.7		120.7

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

Pension and Postretirement Benefits

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

	Quarter Ended March 31,	
	2006	2005
	(In millions)	
Components of net periodic pension benefit cost		
Service cost	**$ 11.7**	$ 11.1
Interest cost	**20.5**	20.7
Expected return on plan assets	**(22.3)**	(23.9)
Recognized net actuarial loss	**8.6**	5.4
Amortization of unrecognized prior service cost	**1.3**	1.4
Amount capitalized as construction cost	**(2.9)**	(1.7)
Net periodic pension benefit cost (1)	**$ 16.9**	$ 13.0

(1)

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 $8.1 million in 2006 and $5.1 million in 2005.

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

	Quarter Ended March 31,	
	2006	**2005**
	(In millions)	
Components of net periodic postretirement benefit cost		
Service cost	**$ 2.1**	$ 1.8
Interest cost	**6.2**	5.7
Amortization of transition obligation	**0.5**	0.5
Recognized net actuarial loss	**2.0**	1.2
Amortization of unrecognized prior service cost	**(0.9)**	(0.8)
Amount capitalized as construction cost	**(2.0)**	(1.8)
Net periodic postretirement benefit cost (1)	**$ 7.9**	$ 6.6

(1) *BGE's portion of our net periodic postretirement benefit cost was $6.3 million in 2006 and $5.8 million in 2005.*

Our non-qualified pension plans and our postretirement benefit programs are not funded; however, we have trust assets securing certain executive pension benefits. We estimate that we will incur approximately $3 million in pension benefit payments for our non-qualified pension plans and approximately $27 million for retiree health and life insurance benefit payments during 2006. We contributed $52 million to our qualified pension plans in March 2006, even though there was no IRS required minimum contribution in 2006.

Financing Activities

At March 31, 2006, we had $425.0 million of commercial paper outstanding, and at May 5, 2006 we had $330.0 million of commercial paper outstanding.

Constellation Energy had committed bank lines of credit under four credit facilities of $3.6 billion at March 31, 2006 for short-term financial needs. We discuss these facilities in more detail in *Note 8* of our 2005 Annual Report on Form 10-K. These facilities can issue letters of credit up to approximately $3.6 billion. Letters of credit issued under all of our facilities totaled $1.9 billion at March 31, 2006.

Additionally, under our employee benefit plans and shareholder investment plans we issued $18.8 million of common stock during the quarter ended March 31, 2006.

Income Taxes

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

	Quarter Ended March 31,	
	2006	**2005**
	(In millions)	
Income before income taxes (excluding BGE preference stock dividends)	**$ 162.5**	$ 158.0
Statutory federal income tax rate	**35%**	35%
Income taxes computed at statutory federal rate	**56.9**	55.3
(Decreases) increases in income taxes due to:		
Synthetic fuel tax credits(1)	**(18.5)**	(24.6)
State income taxes, net of federal tax benefit	**7.7**	7.0
Other	**0.1**	(1.6)
Total income taxes	**$ 46.2**	$ 36.1
Effective tax rate	**28.5%**	22.8%

Synthetic fuel tax credits are net of our expectation of a 46% phase-out in 2006 based on market forwards and volatilities at March 31, 2006 (approximately $16 million for the quarter ended March 31, 2006). Based on market forwards and volatilities as of April 28, 2006, we estimate a 70% tax credit phase-out in 2006 (approximately $95 million for the year 2006). The expected amount of synthetic fuel tax credits phased-out may change materially from period to period as a result of continued changes in oil prices.

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 electric business enters into various long-term contracts for the procurement of electricity. These contracts expire between 2006 and 2009. Our regulated gas business has gas transportation and storage contracts that expire between 2006 and 2028. As discussed in *Note 1* of our 2005 Annual Report on Form 10-K, the costs under these contracts are fully recoverable by our regulated businesses.

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

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

At March 31, 2006, the total amount of commitments was $6,778.1 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				
	2006	2007-2008	2009-2010	Thereafter	Total
			(In millions)		
Competitive supply	$ 5,417.9	$ 989.0	$ 245.0	$ 1,860.2	$ 8,512.1
Other	5.3	13.5	1.7	1,276.2	1,296.7
Total guarantees	$ 5,423.2	$ 1,002.5	$ 246.7	$ 3,136.4	$ 9,808.8

At March 31, 2006, we had a total of $9,808.8 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, and we do not expect to fund the full amount under these guarantees.

Constellation Energy guaranteed $8,512.1 million on behalf of our subsidiaries for competitive supply activities. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. While the face amount of these guarantees is $8,512.1 million, our calculated fair value of obligations covered by these guarantees was $2,513.3 million at March 31, 2006. If the parent company was required to fund these subsidiary obligations, the total amount based on March 31, 2006 market prices would be $2,513.3 million. The recorded fair value of obligations in our Consolidated Balance Sheets for guarantees was $1,093.3 million at March 31, 2006.

Constellation Energy guaranteed $947.0 million primarily on behalf of our nuclear generating facilities mostly due 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 March 31, 2006.

Our merchant energy business guaranteed $19.2 million for loans and other performance guarantees related to certain power projects in which we have an investment.

Our other nonregulated business guaranteed $7.7 million for performance bonds.

BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At March 31, 2006, 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.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets at March 31, 2006 was $1.1 billion and not the $9.8 billion of total guarantees. We assess the risk of loss from 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. The EPA and potentially responsible parties, including BGE, filed cost recovery claims against Metal Bank of America for an equitable share of expected site remediation costs. In March 2006, all claims were settled. Under the terms of the settlement, the potentially responsible parties will remediate the site and the costs of the clean-up will be paid from funds held in trust for that purpose. BGE is not required to contribute to the trust and we do not believe the potentially responsible parties will incur clean-up costs in excess of the amount held by the trust; therefore, in March 2006, we reversed the previously recorded liability.

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 and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In April 2006, a settlement was reached among the EPA and the potentially responsible parties with respect to investigation of the site. The settlement, which will become effective on May 30, 2006, requires the potentially responsible parties, over the course of several years, to identify contamination at the site and recommend clean-up options. The clean-up costs will not be known until the investigation is complete. However, those costs could have a material effect on our, and BGE's, 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 and in November 2005 issued an order, expected to become effective in the second quarter of 2006, requiring cleanup of the site by those parties as well as 15 other parties. 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 March 31, 2006, BGE has spent approximately $40 million for remediation at this site.

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

Air Quality

In late July 2005, we received two Notices of Violation (NOVs) from the Placer County Air Pollution Control District, Placer County California (District) alleging that the Rio Bravo Rocklin facility located in Lincoln, California had violated certain District air emission regulations. We have a combined 50% ownership interest in the partnership which owns the Rio Bravo Rocklin facility. The NOVs allege a total of 38 violations between January 2003 and March 2005 of either the facility's air permit or federal, state, and county air emission standards related to nitrogen oxide, carbon monoxide, and particulate emissions, as well as violations of certain monitoring and reporting requirements during that time period. The maximum civil penalties for the alleged violations range from $10,000 to $40,000 per violation. Management of the Rio Bravo Rocklin facility is currently 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.

Litigation

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

Western Power Markets

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

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, involving claims related to approximately 132 children, have been filed to date, with each claimant seeking $20 million in compensatory damages, plus punitive damages, from us.

In rulings applicable to all but six of the cases, involving claims related to approximately 50 children, the Circuit Court for Baltimore City dismissed with prejudice all claims against BGE and Constellation Energy. Plaintiffs may attempt to pursue appeals of the rulings in favor of BGE and Constellation Energy once the cases are finally concluded as to all defendants. We believe that we have meritorious defenses and intend to defend the actions vigorously. However, we cannot predict the timing, or outcome, of these cases, or their possible effect on our, or BGE's, financial results.

Asbestos

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

Approximately 519 individuals who were never employees of BGE have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE in these actions. To date, most asbestos claims against us have been dismissed or resolved without any payment and a small minority have been resolved for amounts that were not material to our financial results. The remaining claims are currently pending in state courts in Maryland and Pennsylvania.

BGE does not know the specific facts necessary to estimate its potential liability for these claims. The specific facts BGE does not know include:

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

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

Insurance

We discuss our nuclear and non-nuclear insurance programs in *Note 12* of our 2005 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 2005 Annual Report on Form 10-K.

Interest Rates

We use interest rate swaps to manage our interest rate exposures 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, 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 $14.7 million at March 31, 2006 and $15.4 million at December 31, 2005. 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 an unrealized pre-tax loss of $6.5 million at March 31, 2006 and an unrealized pre-tax loss of $0.9 million at December 31, 2005 and was recorded as an increase in our "Risk management liabilities" and a decrease in our "Long-term debt." We have not recognized any hedge ineffectiveness on these interest rate swaps.

Commodity Prices

At March 31, 2006 our merchant energy business had designated certain purchase and sale contracts as cash-flow hedges of forecasted transactions for the years 2006 through 2015 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.

Our merchant energy business has net unrealized pre-tax losses of $1,605.6 million at March 31, 2006 and $517.1 million at December 31, 2005 on these hedges recorded in "Accumulated other comprehensive income." We expect to reclassify $610.8 million of net pre-tax losses on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at March 31, 2006. However, the actual amount reclassified into earnings could vary from the amounts recorded at March 31, 2006 due to future changes in market prices. We recognized into earnings a pre-tax loss of $5.2 million for the quarter ended March 31, 2006 and a pre-tax gain of $11.6 million for the quarter ended March 31, 2005 related to the ineffective portion of our hedges. In addition, during the quarter ended March 31, 2006, we de-designated contracts previously designated as cash-flow hedges for which the forecasted transaction originally hedged is no longer probable and as a result we recognized a pre-tax loss of $10.5 million.

Our merchant energy business also enters into natural gas storage contracts under which the gas in storage qualifies for fair value hedge accounting treatment under SFAS No. 133. For the quarter ended March 31, 2006, we had unrealized pre-tax gains of $1.8 million and unrealized pre-tax losses of $2.8 million due to hedge ineffectiveness resulting in a pre-tax net loss of $1.0 million being 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

FSP FIN 46R-6

In April 2006, the FASB issued Staff Position (FSP) FIN 46R-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R.* FSP FIN 46R-6 addresses how a reporting enterprise should determine the variability to be considered in applying FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities an Interpretation of ARB No. 51*. The variability to be considered should be based on an analysis of the design of the entity and should consider the nature of the entity's risks and the purpose for which the entity was created. FSP FIN 46R-6 must be applied prospectively to all entities beginning July 1, 2006. We are currently assessing the impact FSP FIN 46R-6 may have on our, or BGE's, financial results.

Accounting Standards Adopted

FSP 115-1 and 124-1

In November 2005, FSP SFAS 115-1 and SFAS 124-1 (FSP 115-1 and 124-1), *The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments,* was issued to replace the measurement and recognition criteria of EITF 03-1. FSP 115-1 and 124-1 references existing guidance in SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* SEC Staff Accounting Bulletin No. 59, *Accounting for Noncurrent Marketable Equity Securities*, and APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*. FSP 115-1 and 124-1 requires an other-than-temporary analysis to be completed each reporting period (i.e., every quarter) beginning after December 15, 2005. The adoption of this standard did not have a material impact on our, or BGE's, financial results.

Related Party Transactions BGE

Income Statement

BGE provides standard offer service to those customers that do not choose an alternate electric supplier. Our wholesale marketing and risk management operation supplies a portion of BGE's standard offer service obligation to commercial and industrial customers and provides BGE 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 customers beyond June 30, 2006, will occur from time to time through a competitive bidding process approved by the Maryland PSC.

The cost of BGE's purchased energy from nonregulated subsidiaries of Constellation Energy to meet its standard offer service obligation was $187.6 million for the quarter ended March 31, 2006 compared to $213.1 million for the same period in 2005.

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. These costs were approximately $31.6 million for the quarter ended March 31, 2006 compared to $25.0 million for the quarter ended March 31, 2005.

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. Under this arrangement, BGE had invested $91.7 million at March 31, 2006 and had borrowed $3.2 million at December 31, 2005.

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 an energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in the *Notes to Consolidated Financial Statements* on page 13.

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE. We discuss our business in more detail in *Item 1 Business* section of our 2005 Annual Report on Form 10-K and we discuss the risks affecting our business in *Item 1A. Risk Factors* on page 44.

Our 2005 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 derivative 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 ended March 31, 2006 and 2005. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- We describe changes to our business environment during the year.
- We highlight significant events that occurred in 2006 that are important to understanding our results of operations and financial condition.
- We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition, addressing our sources and uses of cash, capital resources, commitments, and liquidity.
- We conclude with a discussion of our exposure to various market risks.

Business Environment

With the evolving regulatory environment surrounding customer choice, increasing competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section on page 45 and in *Item 1A. Risk Factors* on page 44. We discuss our market risks in the *Market Risk* section beginning on page 41.

In this section, we discuss in more detail events which have impacted our business during the quarter ended March 31, 2006.

Regulation by the Maryland PSC

Base Rates

As a result of the deregulation of electric generation in Maryland, BGE's residential electric base rates are frozen until July 2006. In March 2006, the Maryland Public Service Commission (Maryland PSC) approved a transition plan as a result of the significant increase in Provider of Last Resort (POLR) prices that will take place upon the expiration of the residential rate freeze. The key elements of the plan are:

- All residential electric customers will be enrolled in the plan unless they elect to opt out.

Limited income residential electric customers have a 35 month plan, beginning in July 2006 and ending in May 2009. All other residential electric customers have a 23 month plan, beginning in July 2006 and ending in May 2008.

During the first eight months of the plan, residential electric rates will increase so that by March 2007, residential electric rates will reach market-based levels. In July 2006, residential electric rates will increase by 21% and then increase gradually each of the next seven months. During these eight months, BGE is authorized to defer recovery of the costs to serve residential electric customers in excess of each month's actual rates.

During the remaining period of the plan, BGE will collect full market-based rates, and will also recover the deferred costs from residential electric customers, including a financing charge at an annual rate of 5%.

On April 20, 2006, BGE filed proposed amendments to the plan. In an order issued on April 28, 2006, the Maryland PSC approved an amended plan with the following key elements:

BGE residential customers would be required to select or "opt-in" to the plan to defer a portion of the rate increase.

Customers who opt-in would have their rates increase 19.4% on July 1, 2006.

Rates for opt-in customers would increase by another 5% on January 1, 2007 (which may be offset by credits to customers if we complete our merger with FPL Group, as discussed below) and again by approximately 25% on June 1, 2007.

Rates for opt-in customers would increase to market levels on January 1, 2008.

The deferred amount of the rate increase would be repaid by opt-in customers beginning June 1, 2007 through May 2009; limited income customers would have an additional year to repay the deferred amount, through May 2010.

The amended plan provides that customers will not be assessed carrying charges on the deferred amounts. The Maryland PSC ordered, however, that carrying charges equal to BGE's actual short-term borrowing rate on the deferred amount be calculated by BGE for later recovery or offset through one or more mechanisms. BGE has sought rehearing of this aspect of the plan and another party has sought clarification and/or reconsideration of this aspect as well.

Assuming all residential customers participate, we estimate our maximum peak funding requirement at June 1, 2007 to be approximately $400 million under the amended plan or approximately $200 million under the March plan. BGE may have to finance this requirement. If it cannot do so, or cannot do so on favorable terms, our, and BGE's, financial results and liquidity may be materially affected.

In addition to the April plan, if our pending merger with FPL Group is completed, we have offered to provide benefits of approximately $60 million per year for 10 years beginning January 1, 2007 in order to help lower rates for all residential customers, including those who do not opt-in to the rate stabilization plan. We currently estimate the components of the $60 million to include sharing a portion of merger synergies, utilizing the shareholder return component of the residential POLR administrative fees, and redirecting nuclear decommissioning revenue to reduce residential customer rates. However, the amount of benefits to be provided to BGE's customers resulting from our pending merger with FPL Group is the subject of a proceeding currently before the Maryland PSC.

The City of Baltimore has sought judicial review of the Maryland PSC's April 28, 2006 order approving the amended plan, as well as a stay to prevent BGE's implementation of the amended plan. If the stay is granted, BGE may be required to implement the original plan approved by the Maryland PSC in March 2006. We cannot predict whether a court will grant the requested stay, will reverse any aspect of the Maryland PSC's order, or will remand certain issues to the Maryland PSC for reconsideration. The outcome of this proceeding could have a material impact on our, and BGE's, financial results and liquidity.

There is also a possibility that the Maryland General Assembly will enact a plan that would preempt both the original March 2006 plan and the amended April 2006 plan. The Maryland General Assembly may introduce bills in future regularly scheduled or special legislative sessions, which may be enacted into law, that could extend rate caps, limit BGE's ability to recover its costs, or otherwise interfere in the regulatory process. If another plan is enacted into law that would extend rate caps, expand the deferral period, or not allow BGE to fully recover its costs, it could have a material impact on our, and BGE's, financial results and liquidity.

Cost for Decommissioning

Under the Maryland PSC order regarding the deregulation of electric generation, BGE ratepayers must pay a total of $520 million, in 1993 dollars adjusted for inflation, to fund the decommissioning of Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) through fixed annual collections. The fixed annual amount was set at approximately $18.7 million through June 30, 2006. On April 3, 2006, we submitted a filing to the Maryland PSC to determine the fixed annual amount BGE ratepayers will pay after June 30, 2006 for decommissioning Calvert Cliffs.

We proposed that the level of annual collections remain at the current level of approximately $18.7 million until the time of decommissioning. BGE would have the right to review this amount after 10 years to determine if the level of collections continues to be appropriate. As discussed on the previous page, if our pending merger with FPL Group is completed, we have offered to provide benefits of approximately $60 million per year for 10 years to help lower rates for all residential customers. Such benefits may include providing residential customers credits equal to the amount collected annually for decommissioning Calvert Cliffs. However, the amount of benefits to be provided to BGE's customers resulting from our pending merger with FPL Group, as well as the nature of any such benefits, is the subject of a proceeding currently before the Maryland PSC.

Federal Regulation

In May 2005, the 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 became effective 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 this formula approach was allowed by the FERC to become effective subject to refund based on the outcome of a hearing before an administrative law judge. However, the various parties participating in this proceeding have arrived at a settlement resolving all issues, which was approved by the FERC on April 19, 2006. The settlement did not have a material effect on our, or BGE's, financial results.

Environmental Matters

Air Quality and Hazardous Air Emissions

In April 2006, the Healthy Air Act (HAA) was enacted into law in Maryland. The HAA establishes through two phases annual sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury emission caps for specific coal-fired units in Maryland, including units located at three of our facilities. The first phase reduces SO_2 emissions by 74 percent in 2010, NO_x emissions by 59 percent in 2009, and mercury emissions by 80 percent in 2010, all from 2004 levels. The second phase reduces SO_2 emissions by 80 percent in 2013, NO_x emissions by 66 percent in 2012, and mercury emissions by 90 percent in 2013, all from 2004 levels.

In order to implement the requirements of the HAA, the Maryland Department of the Environment (MDE) is expected to finalize its Clean Power Rule (CPR) by the third quarter of 2006. The requirements of the HAA and the CPR for SO_2, NO_x, and mercury emissions are more stringent and apply sooner than those of the existing Clean Air Interstate and the Clean Air Mercury Rules. We discuss the Clean Air Interstate and the Clean Air Mercury Rules in more detail in *Item 1. Business Environmental Matters* section in our 2005 Annual Report on Form 10-K.

Although we continue to evaluate our options, we believe that the environmental capital expenditure estimates provided in *Item 1. Business Environmental Matters* section in our 2005 Annual Report on Form 10-K will be adequate to cover the first phase of emission reduction requirements of the HAA and the CPR. However, our estimates of costs continue to be subject to significant uncertainties including equipment pricing and supplier availability.

For phase two implementation, we are currently assessing our various compliance alternatives, and although we cannot yet estimate the additional costs we may incur, such costs could be material.

New Source Review

In March 2006, the U.S. Court of Appeals for the District of Columbia annulled the equipment replacement rule adopted by the Environmental Protection Agency (EPA) in August 2003, which established a threshold for determining when major new source review requirements are triggered. We believe the court decision, which was anticipated, should have minimal effect on us as it maintains the existing rules for equipment replacement. However, we anticipate that the EPA will continue to examine the existing equipment replacement rules and may again propose new rules. We cannot predict the timing or outcome of any future EPA regulatory action, or its possible effect on our financial results.

Global Climate Change

The HAA and the proposed CPR require that Maryland become a full participant in the Northeast Regional Greenhouse Gas Initiative (RGGI) by 2007. RGGI is a regional cap-and-trade program initially covering carbon dioxide (CO_2) emissions from power plants with capacity greater than 25 megawatts in the affected states. The program aims to stabilize emissions at current levels beginning in 2009 and reduce regional emissions by 10 percent before 2020.

Under the program, it is expected that affected plants would participate in an auction to obtain sufficient CO_2 allowances to support the level of emissions that result from plant operations.

We continue to evaluate the potential impact of the HAA and CPR CO_2 emissions requirements and RGGI participation on our financial results; however, our compliance costs could be material.

Accounting Standards Issued and Adopted

We discuss recently issued and adopted accounting standards in the *Accounting Standards Issued* and *Accounting Standards Adopted* sections of the *Notes to Consolidated Financial Statements* beginning on page 19.

Pending Merger with FPL Group, Inc.

On December 18, 2005, Constellation Energy entered into an Agreement and Plan of Merger with FPL Group, Inc. We discuss the details of this pending merger in *Note 15* of our 2005 Annual Report on Form 10-K.

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

Events of 2006

Residential Electric Rates

We discuss the Maryland PSC residential electric rate transition plan in more detail in the *Regulation by the Maryland PSC* section beginning on page 21.

Commodity Prices

During the quarter ended March 31, 2006, we continued to experience significant changes in commodity prices. This volatile commodity price environment continues to impact our results of operations and financial condition, as discussed in more detail in the following sections:

Financial Condition beginning on page 37,

Mark-to-Market beginning on page 28,

Risk Management Assets and Liabilities on page 32,

Market Risk on page 41, and

Notes to Consolidated Financial Statements on page 19.

Synthetic Fuel Tax Credits

As discussed in our 2005 Annual Report on Form 10-K, the Internal Revenue Code provides for a phase-out of synthetic fuel tax credits if average annual wellhead oil prices increase above certain levels. For 2006, we estimate the tax credit reduction would begin if the reference price exceeds approximately $54 per barrel and would be fully phased out if the reference price exceeds approximately $68 per barrel.

During the quarter ended March 31, 2006, oil prices remained at historically high levels. Based on market forwards and volatilities and current production levels as of March 31, 2006, we estimate a 46% tax credit phase-out in 2006 (approximately $65 million). As a result, the amount of tax credits recognized in the first quarter of 2006 reflects the estimated 46% tax credit phase-out (approximately $16 million).

Subsequent to March 31, 2006, oil prices have continued to increase. Based on market forwards and volatilities and current production levels as of April 28, 2006, we estimate a 70% tax credit phase-out in 2006 (approximately $95 million) and a 60% tax credit phase-out in 2007 (approximately $85 million). However, the ultimate amount of tax credits phased-out for 2006 and 2007, if any, is subject to change based on the actual reference price and production levels for the entire year. In addition, our ability to claim synthetic fuel tax credits and the potential phase-out of these credits could be materially impacted by any future legislative changes to the Internal Revenue Code.

We actively monitor and manage our exposure to synthetic fuel tax credit phase-out as part of our ongoing hedging activities. In addition, we are exploring various options, including the suspension or cessation of synthetic fuel production depending on our expectation of the level of tax credit phase-out.

Ginna Workforce Reduction

During the quarter ended March 31, 2006, we incurred costs associated with a planned workforce restructuring at our R. E. Ginna Nuclear Power Plant (Ginna). We discuss this restructuring in more detail in the *Notes to Consolidated Financial Statements* on page 11.

Asset Acquisition

In March 2006, we acquired working interests in a gas and oil producing field. We discuss this acquisition in more detail in the *Notes to Consolidated Financial Statements* on page 13.

Results of Operations for the Quarter Ended March 31, 2006 Compared with the Same Period of 2005

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. Changes in other income, fixed charges, and income taxes are discussed, as necessary, in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 36.

Overview

Results

	Quarter Ended March 31, 2006	Quarter Ended March 31, 2005
	(In millions, after-tax)	
Merchant energy	**$ 43.6**	$ 48.5
Regulated electric	**33.6**	43.5
Regulated gas	**35.0**	27.6
Other nonregulated	**0.8**	(1.0)
Income from continuing operations	**113.0**	118.6
Income from discontinued operations	**0.9**	2.1
Net Income	**$ 113.9**	$ 120.7
Other Items Included in Operations:		
Non-qualifying hedges	**$ (9.7)**	$ (8.2)
Merger-related costs	**(1.5)**	
Workforce reduction costs	**(1.3)**	
Total Other Items	**$ (12.5)**	$ (8.2)

Quarter Ended March 31, 2006

Our total net income for the quarter ended March 31, 2006 decreased $6.8 million, or $0.05 per share, compared to the same period of 2005 mostly because of the following:

We had lower earnings of approximately $50 million after-tax at our merchant energy business due to lower gross margin from the Mid-Atlantic Region. We discuss this decrease in gross margin in more detail in the *Mid-Atlantic Region* section beginning on page 27.

We had lower earnings of $9.9 million after-tax from our regulated electric business primarily due to higher operations and maintenance expenses and lower revenues less electricity purchased for resale expenses.

We had lower earnings of $8.1 million after-tax at our synthetic fuel facilities due to the expected phase-out of tax credits as a result of the high price of oil. We discuss this phase-out of tax credits in more detail in the *Events of 2006* section on the previous page.

We had lower earnings of $5.8 million after-tax at our retail competitive supply operation primarily due to higher operating expenses mostly due to the growth of this operation and higher uncollectible expense, partially offset by an increase in gross margin. We discuss our retail gross margin in more detail in the *Competitive Supply* section on page 28.

We had lower earnings of $2.8 million after-tax due to incurring additional merger-related costs associated with our pending merger with FPL Group and workforce reduction costs associated with a restructuring at our Ginna facility. We discuss these costs in more detail in the *Notes to Consolidated Financial Statements* beginning on page 11.

These decreases were partially offset by the following:

We had higher earnings of approximately $63 million after-tax due to higher gross margin, partially offset by increased operating expenses at our wholesale competitive supply operation. We discuss our mark-to-market and wholesale accrual results in more detail in the *Competitive Supply* section beginning on page 28.

We had higher earnings of $7.4 million after-tax at our regulated gas business primarily due to the favorable impact of the increase in gas base rates that was approved in December 2005. We discuss the gas base rate increase in more detail in the *Regulated Gas Business* section on page 35.

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 2005 Annual Report on Form 10-K.

Our merchant energy business focuses on delivery of physical, customer-oriented products to producers and consumers, manages the risk and optimizes the value of our owned generation assets, and uses our portfolio management and trading capabilities both to manage risk and to deploy risk capital to generate additional returns.

We 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 2005 Annual Report on Form 10-K. We summarize our revenue and expense recognition policies as follows:

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

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

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

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of certain contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our results in the *Competitive Supply Mark-to-Market* section beginning on page 28.

Our wholesale marketing and risk management operation actively transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of these activities we trade energy and energy-related commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines, and may have a material impact on our financial results. We discuss the impact of our trading activities and value at risk in more detail in the *Competitive Supply Mark-to-Market* section beginning on page 28 and the *Market Risk* section on page 41.

Results

	Quarter Ended March 31,	
	2006	**2005**
	(In millions)	
Revenues	**$ 4,121.6**	$ 2,893.1
Fuel and purchased energy expenses	**(3,549.1)**	(2,382.9)
Operating expenses	**(375.6)**	(329.9)
Workforce reduction costs	**(2.2)**	
Merger-related costs	**(1.3)**	
Depreciation, depletion, and amortization	**(68.2)**	(62.9)
Accretion of asset retirement obligations	**(16.5)**	(15.1)
Taxes other than income taxes	**(30.8)**	(24.5)
Income from Operations	**$ 77.9**	$ 77.8
Income from continuing operations (after-tax)	**$ 43.6**	$ 48.5
Income from discontinued operations (after-tax)		0.4
Net Income	**$ 43.6**	$ 48.9

	Quarter Ended March 31,	
Other Items Included in Operations (after-tax):		
Non-qualifying hedges	**$ (9.7)**	$ (8.2)
Merger-related costs	**(1.0)**	
Workforce reduction costs	**(1.3)**	
Total Other Items	**$ (12.0)**	$ (8.2)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 14 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 may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

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

Mid-Atlantic Region our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region. This also includes active portfolio management of the generating assets and other physical and financial contractual arrangements, as well as other PJM competitive supply activities.

Plants with Power Purchase Agreements our 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.

Wholesale Competitive Supply our marketing and risk management operation that provides energy products and services (including portfolio management and trading activities) outside the Mid-Atlantic Region primarily to distribution utilities, power generators, and other wholesale customers. We also provide global coal and upstream and downstream natural gas services.

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

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

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

	Quarter Ended March 31,	
	2006	2005
	(Dollar amounts in millions)	
Revenues:		
Mid-Atlantic Region	**$ 465.4**	$ 494.8
Plants with Power Purchase Agreements	**190.7**	192.5
Competitive Supply		
Retail	**2,024.2**	1,320.5
Wholesale	**1,420.5**	868.5
Other	**20.8**	16.8
Total	**$ 4,121.6**	$ 2,893.1
Fuel and purchased energy expenses:		
Mid-Atlantic Region	**$ (366.1)**	$ (313.4)
Plants with Power Purchase Agreements	**(16.8)**	(15.3)
Competitive Supply		
Retail	**(1,950.9)**	(1,257.5)
Wholesale	**(1,215.3)**	(796.7)
Other		
Total	**$ (3,549.1)**	$ (2,382.9)

	Quarter Ended March 31,			
Gross Margin:		**% of Total**		**% of Total**
Mid-Atlantic Region	**$ 99.3**	**17%**	$ 181.4	36%
Plants with Power Purchase Agreements	**173.9**	**30**	177.2	35
Competitive Supply				
Retail	**73.3**	**13**	63.0	12
Wholesale	**205.2**	**36**	71.8	14
Other	**20.8**	**4**	16.8	3
Total	**$ 572.5**	**100%**	$ 510.2	100%

Mid-Atlantic Region

	Quarter Ended March 31, 2006	2005
	(In millions)	
Revenues	**$ 465.4**	$ 494.8
Fuel and purchased energy expenses	**(366.1)**	(313.4)
Gross margin	**$ 99.3**	$ 181.4

The decrease in gross margin during the quarter ended March 31, 2006 compared to the same period of 2005 is primarily due to:

lower gross margin of approximately $45 million mostly because of a higher level of variable costs, including higher emissions and coal costs, and less megawatt hours served at lower contract rates compared to the same period of 2005, lower generation at Calvert Cliffs mostly because of a longer planned refueling outage that included replacement of the reactor vessel head, which resulted in lower gross margin of approximately $17 million, and

lower competitive transition charge (CTC) revenues of approximately $13 million due to commercial and industrial customers that completed their obligation in July 2005 and the continued decline in the CTC rate. We discuss our CTC revenues over time in more detail in our 2005 Annual Report on Form 10-K.

Plants with Power Purchase Agreements

	Quarter Ended March 31, 2006	Quarter Ended March 31, 2005
	(In millions)	
Revenues	**$ 190.7**	$ 192.5
Fuel and purchased energy expenses	**(16.8)**	(15.3)
Gross margin	**$ 173.9**	$ 177.2

Gross margin from our Plants with Power Purchase Agreements was about the same during the quarter ended March 31, 2006 compared to the same period of 2005.

Competitive Supply

Retail

	Quarter Ended March 31, 2006	Quarter Ended March 31, 2005
	(In millions)	
Accrual revenues	**$ 2,016.8**	$ 1,321.6
Fuel and purchased energy expenses	**(1,934.0)**	(1,257.5)
Retail accrual activities	**82.8**	64.1
Mark-to-market results recorded in earnings	**(9.5)**	(1.1)
Gross margin	**$ 73.3**	$ 63.0

The increase in gross margin from our retail competitive supply activities during the quarter ended March 31, 2006 compared to the same period of 2005 is primarily due to serving 2.2 million more megawatt hours and the positive impact of higher realized contract margins per megawatt hour. These increases in gross margin were partially offset by higher losses on mark-to-market contracts mostly due to a higher number of mark-to-market contracts during the quarter ended March 31, 2006 compared to the same period of 2005 and a decrease in prices during the first quarter of 2006.

Wholesale

	Quarter Ended March 31, 2006	Quarter Ended March 31, 2005

	Quarter Ended March 31,	
	2006	2005
	(In millions)	
Accrual revenues	**$ 1,323.2**	$ 846.0
Fuel and purchased energy expenses	**(1,215.3)**	(796.7)
Wholesale accrual activities	**107.9**	49.3
Mark-to-market results recorded in earnings	**97.3**	22.5
Gross Margin	**$ 205.2**	$ 71.8

We analyze our wholesale accrual and mark-to-market competitive supply activities separately below.

Wholesale Accrual Activities

Our wholesale marketing and risk management operation had higher gross margin during the quarter ended March 31, 2006 compared to the same period of 2005 primarily due to:

- approximately $40 million primarily due to new contracts entered into during 2006, higher realized gross margin associated with existing contracts, and the favorable impact of higher energy prices, partially offset by the absence of the favorable impact related to the monetization of a power purchase agreement during the first quarter of 2005 and hedge ineffectiveness, and
- approximately $19 million related to our international coal operations and our upstream and downstream natural gas activities.

Mark-to-Market

Mark-to-market results recorded in earnings include net gains and losses from origination, trading, and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section of our 2005 Annual Report on Form 10-K.

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market earnings will fluctuate. We cannot predict these fluctuations, but the impact on our earnings could be material. We discuss our market risk in more detail in the *Market Risk* section on page 41. The primary factors that cause fluctuations in our mark-to-market results recorded in 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 results recorded in earnings were as follows:

	Quarter Ended March 31, 2006	Quarter Ended March 31, 2005
	(In millions)	
Unrealized mark-to-market results recorded in earnings		
Origination gains	**$ 3.3**	$ 1.9
Risk management and trading mark-to- market		
Unrealized changes in fair value	**84.5**	19.5
Changes in valuation techniques		
Reclassification of settled contracts to realized	**(124.1)**	11.8
Total risk management and trading mark-to- market	**(39.6)**	31.3
Total unrealized mark-to-market*	**(36.3)**	33.2
Realized mark-to-market	**124.1**	(11.8)
Total mark-to-market results recorded in earnings	**$ 87.8**	$ 21.4

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

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

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

Risk management and trading mark-to-market represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the recognition of gains associated with decreases in the close-out adjustment when we are able to obtain sufficient market price information. We discuss the changes in mark-to-market results recorded in earnings below. We show the relationship between our mark-to-market results recorded in earnings and the change in our net mark-to-market energy asset later in this section.

Mark-to-market results recorded in earnings increased $66.4 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly because of an increase in unrealized changes in fair value. Unrealized changes in fair value increased $88.3 million primarily due to a higher level of risk management and trading mark-to-market activities mostly due to a higher level of open power positions that resulted in increased gains. We deployed more risk capital in order to earn additional returns during the quarter ended March 31, 2006 compared to the same period of 2005.

The increase in unrealized changes in fair value was partially offset by the absence of a $23.3 million favorable impact related to changes in the close-out adjustment during the quarter ended March 31, 2006 compared to the same period of 2005. These close-out adjustments are determined by the change in open positions, new transactions where we did not have observable market price information, and existing transactions where we have now observed sufficient market price information and/or we realized cash flows since the transactions' inception. We discuss the close-out adjustment in more detail in the *Critical Accounting Policies* section of our 2005 Annual Report on Form 10-K.

Mark-to-Market Energy Assets and Liabilities

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

	March 31, 2006	December 31, 2005
	(In millions)	
Current Assets	**$ 938.4**	$ 1,339.2
Noncurrent Assets	**858.5**	1,089.3
Total Assets	**1,796.9**	2,428.5
Current Liabilities	**801.4**	1,348.7
Noncurrent Liabilities	**635.9**	912.3
Total Liabilities	**1,437.3**	2,261.0
Net mark-to-market energy asset	**$ 359.6**	$ 167.5

The following are the primary sources of the change in the net mark-to-market energy asset during the quarter ended March 31, 2006:

	(In millions)	
Fair value beginning of period		$ 167.5
Changes in fair value recorded in earnings		
Origination gains	$ 3.3	
Unrealized changes in fair value	84.5	
Changes in valuation techniques		
Reclassification of settled contracts to realized	(124.1)	
Total changes in fair value recorded in earnings		(36.3)
Contracts acquired		
Changes in value of exchange-listed futures and options		140.7
Net change in premiums on options		84.7
Other changes in fair value		3.0
Fair value at end of period		$ 359.6

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

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

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

Changes in valuation techniques represent improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to more accurately reflect the 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 in our Consolidated Statements of Income:

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

Changes in value of exchange-listed futures and options are adjustments to remove unrealized changes in fair value of exchange-traded contracts that are included in risk management and trading mark-to-market results. 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 March 31, 2006 are as follows:

	Settlement Term							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Fair Value**
				(In millions)				
Prices provided by external sources (1)	$ 125.0	$ (4.0)	$ 186.4	$ 21.9	$ (1.0)	$	$	$ 328.3
Prices based on models	11.5	16.4	(1.8)	(17.5)	18.2	1.6	2.9	31.3
Total net mark-to-market energy asset	$ 136.5	$ 12.4	$ 184.6	$ 4.4	$ 17.2	$ 1.6	$ 2.9	$ 359.6

(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 on the previous page 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 below.

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

- forward and swap purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2008, but up to 2010, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2008, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms primarily through 2007, but up to 2008, depending upon the region,
- forward and swap purchases and sales of natural gas, coal and oil for delivery terms primarily through 2009, 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 March 31, 2006 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:

	March 31, 2006	December 31, 2005
	(In millions)	
Current Assets	**$ 438.9**	$ 1,244.3
Noncurrent Assets	**459.8**	626.0
Total Assets	**898.7**	1,870.3
Current Liabilities	**654.2**	483.5
Noncurrent Liabilities	**968.6**	1,035.5
Total Liabilities	**1,622.8**	1,519.0
Net risk management (liability) asset	**$ (724.1)**	$ 351.3

The decrease in our net risk management asset since December 31, 2005 of $1,075.4 million was due primarily to decreases in power prices that reduced the fair value of our short-term cash-flow hedge positions and the settlement of cash-flow hedges during the quarter ended March 31, 2006. A decrease in the fair value of our cash-flow hedges indicates an increase in value of the accrual positions for which our hedges were established.

Other

	Quarter Ended March 31,	
	2006	2005
	(In millions)	
Revenues	**$ 20.8**	$ 16.8

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 2005 Annual Report on Form 10-K.

We discuss certain risks and uncertainties in more detail in the *Forward Looking Statements* section on page 45 and in *Item 1A. Risk Factors* section on page 44. 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 $45.7 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly due to the following:

- an increase at our competitive supply operations totaling $37.9 million primarily related to higher compensation and benefit costs and the impact of inflation on other costs due to the continued growth of these operations, and
- an increase of $10.3 million at our High Desert facility related to planned outage costs.

These increases in expenses were partially offset by lower operating expenses of $5.2 million at Nine Mile Point related to lower contractor and other outage costs for the refueling outage that occurred in the first quarter of 2006 compared to the refueling outage in the first quarter of 2005.

Workforce Reduction Costs

Our merchant energy business recognized expenses associated with our workforce reduction efforts at our Ginna facility as discussed in more detail in the *Notes to the Consolidated Financial Statements* on page 11.

Merger-Related Costs

We discuss our pending merger with FPL Group and related costs in more detail in the *Notes to the Consolidated Financial Statements* on page 12.

Depreciation, Depletion, and Amortization Expense

Merchant energy depreciation, depletion, and amortization expense increased $5.3 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly due to $4.2 million related to our working interests in gas producing fields in Texas and Alabama which were acquired in June 2005.

Taxes Other Than Income Taxes

Merchant energy taxes other than income taxes increased $6.3 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly due to $4.5 million related to higher gross receipts taxes at our retail electric operation and $1.4 million related to our working interests in gas producing fields in Texas and Alabama.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section of our 2005 Annual Report on Form 10-K.

Results

	Quarter Ended March 31,	
	2006	**2005**
	(In millions)	
Revenues	**$ 504.0**	$ 491.5
Electricity purchased for resale expenses	**(262.9)**	(242.1)
Operations and maintenance expenses	**(84.4)**	(75.9)
Merger-related costs	**(0.4)**	
Depreciation and amortization	**(45.8)**	(47.4)
Taxes other than income taxes	**(34.0)**	(34.4)

	Quarter Ended March 31,	
Income from Operations	**$ 76.5**	$ 91.7
Net Income	**$ 33.6**	$ 43.5
Other Items Included in Operations (after-tax):		
Merger-related costs	**$ (0.3)**	$

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

Net income from the regulated electric business decreased $9.9 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly because of increased operations and maintenance expenses of $5.2 million after-tax and decreased revenues less electricity purchased for resale expenses of $5.1 million after-tax.

Electric Revenues

The changes in electric revenues during the quarter ended March 31, 2006 compared to the same period of 2005 were caused by:

	Quarter Ended March 31, 2006 vs. 2005
	(In millions)
Distribution volumes	$ (9.0)
Standard offer service	18.8
Total change in electric revenues from electric system sales	9.8
Other	2.7
Total change in electric revenues	$ 12.5

<u>*Distribution Volumes*</u>

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

The percentage changes in our electric distribution volumes, by type of customer, during the quarter ended March 31, 2006 compared to the same period of 2005 were:

	Quarter Ended March 31, 2006 vs. 2005
Residential	(7.1)%
Commercial	(2.2)
Industrial	(2.4)

During the quarter ended March 31, 2006, we distributed less electricity to residential and commercial customers compared to the same period of 2005 mostly due to milder winter weather and decreased usage per customer, partially offset by an increased number of customers. We distributed less electricity to industrial customers mostly due to decreased usage per customer.

<u>*Standard Offer Service*</u>

BGE provides standard offer service for customers that do not select an alternative generation supplier as discussed in *Item 1. Business Electric Regulatory Matters and Competition* section of our 2005 Annual Report on Form 10-K. We discuss the Maryland PSC residential electric rate transition plan in the *Regulation by the Maryland PSC* section beginning on page 21.

Standard offer service revenues increased during the quarter ended March 31, 2006 compared to the same period of 2005 mostly due to an increase in the standard offer service rates for customers partially offset by lower standard offer service sales volumes.

Electricity Purchased for Resale Expenses

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

Electricity purchased for resale expenses increased $20.8 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly due to increased costs to serve standard offer service customers partially offset by decreased standard offer service volumes.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $8.5 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly due to $5.1 million of incremental distribution service restoration expenses associated with winter storms in 2006, higher compensation and benefit costs, and the impact of inflation on other costs.

Merger-Related Costs

We discuss our pending merger with FPL Group and related costs in more detail in the *Notes to the Consolidated Financial Statements* on page 12.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section of our 2005 Annual Report on Form 10-K.

Results

	Quarter Ended March 31,	
	2006	**2005**

	Quarter Ended March 31,	
	(In millions)	
Revenues	**$ 420.2**	$ 365.8
Gas purchased for resale expenses	**(298.4)**	(260.3)
Operations and maintenance expenses	**(35.6)**	(31.9)
Merger-related costs	**(0.2)**	
Depreciation and amortization	**(11.9)**	(12.2)
Taxes other than income taxes	**(9.5)**	(9.4)
Income from operations	**$ 64.6**	$ 52.0
Net Income	**$ 35.0**	$ 27.6
Other Items Included in Operations (after-tax):		
Merger-related costs	**$ (0.2)**	$

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

Net income from the regulated gas business increased $7.4 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly because of increased revenues less gas purchased for resale expenses of $9.9 million after-tax, which was primarily due to the increase in gas base rates that was approved by the Maryland PSC in December 2005. This increase was partially offset by higher operations and maintenance expenses of $2.2 million after-tax.

Gas Revenues

The changes in gas revenues during the quarter ended March 31,2006 compared to the same period of 2005 were caused by:

	Quarter Ended March 31, 2006 vs. 2005
	(In millions)
Distribution volumes	$ (18.4)
Base rates	14.4
Weather normalization	14.2
Gas cost adjustments	31.1
Total change in gas revenues from gas system sales	41.3
Off-system sales	12.0
Other	1.1
Total change in gas revenues	$ 54.4

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, during the quarter ended March 31, 2006 compared to the same period of 2005 were:

	Quarter Ended March 31, 2006 vs. 2005
Residential	(17.8)%
Commercial	(21.0)
Industrial	29.1

During the quarter ended March 31, 2006, we distributed less gas to residential and commercial customers compared to the same period of 2005 mostly due to milder winter weather and decreased usage per customer, partially offset by an increased number of customers. We distributed more gas to industrial customers mostly due to increased usage per customer.

Base Rates

The Maryland PSC issued an order in December 2005 granting BGE an annual increase in its gas base rates of $35.6 million. Certain parties to the proceeding have sought judicial review and Maryland PSC rehearing of the decision. BGE will not seek review of any aspect of the order. We cannot provide assurance that a court will not reverse any aspect of the order or that it will not remand certain issues to the Maryland PSC.

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 sales 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 2005 Annual Report on Form 10-K.

Gas cost adjustment revenues increased during the quarter ended March 31, 2006 compared to the same period of 2005 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 ended March 31, 2006 compared to the same period of 2005 because we sold gas at higher prices partially offset by less gas sold.

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 $38.1 million during the quarter ended March 31, 2006 compared to the same period of 2005 because the gas we purchased was at higher prices partially offset by less gas purchased.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased $3.7 million during the quarter ended March 31, 2006 compared to the same period of 2005 mostly due to higher compensation and benefit costs and the impact of inflation on other costs.

Merger-Related Costs

We discuss our pending merger with FPL Group and related costs in more detail in the *Notes to the Consolidated Financial Statements* on page 12.

Other Nonregulated Businesses

Results

	Quarter Ended March 31, 2006	Quarter Ended March 31, 2005
	(In millions)	
Revenues	**$ 60.9**	$ 48.5
Operating expenses	**(48.4)**	(39.8)
Depreciation and amortization	**(8.4)**	(8.1)
Taxes other than income taxes	**(0.6)**	(0.2)
Income from Operations	**$ 3.5**	$ 0.4
Income from continuing operations (after-tax)	**$ 0.8**	$ (1.0)
Income from discontinued operations (after-tax)	**0.9**	1.7
Net Income	**$ 1.7**	$ 0.7

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

As previously discussed in our 2005 Annual Report on Form 10-K, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we will continue to hold and own over the next several years. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in additional losses.

Consolidated Nonoperating Income and Expenses

Income Taxes

During the quarter ended March 31, 2006, our income taxes increased $10.1 million compared to the same period of 2005 mostly because of a decrease in synthetic fuel tax credits claimed in 2006 primarily due to the anticipated phase-out of synthetic fuel tax credits. We discuss the phase-out of synthetic tax credits in more detail in the *Events of 2006* section on page 24.

During the quarter ended March 31, 2006, income taxes at BGE decreased $1.4 million compared to the same period of 2005 mostly because of lower pre-tax income.

Financial Condition

Cash Flows

The following table summarizes our cash flows for the quarter ended March 31, 2006 and 2005, excluding the impact of changes in intercompany balances.

	2006 Segment Cash Flows			Consolidated Cash Flows	
	Quarter Ended March 31, 2006			Quarter Ended March 31,	
	Merchant	Regulated	Other	2006	2005
			(In millions)		
Operating Activities					
Net income	$ 43.6	$ 68.6	$ 1.7	$ 113.9	$ 120.7
Non-cash adjustments to net income	42.4	56.6	7.1	106.1	210.8
Changes in working capital	(812.1)	111.5	2.8	(697.8)	51.4
Pension and postemployment benefits*				(30.5)	(33.4)
Other	3.1	10.4	5.6	19.1	0.1
Net cash (used in) provided by operating activities	(723.0)	247.1	17.2	(489.2)	349.6
Investing activities					
Investments in property, plant and equipment	(104.5)	(74.6)	(5.3)	(184.4)	(143.8)
Asset acquisitions and business combinations, net of cash acquired	(100.8)			(100.8)	(3.5)
Investment in nuclear decommissioning trust fund securities	(57.7)			(57.7)	(64.0)
Proceeds from nuclear decommissioning trust fund securities	53.3			53.3	59.6
Sale of investments and other assets	12.9	0.5	1.2	14.6	0.3
Issuances of loans receivable					(176.4)
Other investments	(15.4)	7.9	(3.1)	(10.6)	35.3
Net cash used in investing activities	(212.2)	(66.2)	(7.2)	(285.6)	(292.5)
Cash flows from operating activities less cash flows from investing activities	$ (935.2)	$ 180.9	$ 10.0	(774.8)	57.1
Financing Activities					
Net issuance (repayment) of debt *				406.7	(19.7)
Proceeds from issuance of common stock *				18.8	26.3
Common stock dividends paid *				(59.8)	(50.2)
Proceeds from contract and portfolio acquisitions					308.5
Other *				20.9	(25.4)
Net cash provided by financing activities				386.6	239.5
Net (decrease) increase in cash and cash equivalents				$ (388.2)	$ 296.6

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

Cash Flows from Operating Activities

Cash used in operating activities was $489.2 million in 2006 compared to cash provided by operating activities of $349.6 million in 2005. This $838.8 million decrease was primarily due to unfavorable changes in working capital and a decrease in non-cash adjustments to net income in the first quarter of 2006.

Changes in working capital had a negative impact of $697.8 million on cash flow from operations in 2006 compared to a positive impact of $51.4 million in 2005. The net decrease of $749.2 million was primarily due to commodity price volatility and increased risk management and trading activities that resulted in the following negative working capital changes:

- a net increase of approximately $500 million in collateral requirements, including requirements for exchange-settled transactions. This increase in cash collateral requirements has a corresponding decrease in our letters of credit requirements as discussed in more detail in the *Contractual Payment Obligations and Committed Amounts* section on page 40, and
- an increase in our net mark-to-market energy asset of approximately $190 million. We discuss the changes in our net mark-to-market asset in more detail in the *Mark-to-Market Energy Assets and Liabilities* section on page 30.

Non-cash adjustments to net income decreased by $104.7 million in 2006 compared to 2005 primarily due to the following:

- a decrease in deferred income taxes of $69.9 million,
- the reclassification of $19.6 million of proceeds from derivative power sales contracts as financing activities under SFAS No. 149, *Amendment of FASB Statement No. 133 on Derivative and Hedging Activities*, and
- lower depreciation, depletion, and amortization of $17.9 million.

Cash Flows from Investing Activities

Cash used in investing activities was $285.6 million in 2006 compared to $292.5 million in 2005. The

$6.9 million decrease in cash used in 2006 compared to 2005 was primarily due to the absence in 2006 of $176.4 million from issuances of loans receivable and an increase in cash from the sales of investments and other assets of $14.3 million. This decrease in cash used was mostly offset by the following:

- a $97.3 million increase in cash paid for asset acquisitions and business combinations related to our March 2006 acquisition of working interests in gas and oil producing properties as discussed in more detail in the *Notes to Consolidated Financial Statements* on page 13,
- a decrease of $45.9 million of cash provided by other investing activities, and
- a $40.6 million increase in cash paid for investments in property, plant and equipment.

Cash Flows from Financing Activities

Cash provided by financing activities was $386.6 million in 2006 compared to $239.5 million in 2005. The increase of $147.1 million in cash provided in 2006 compared to 2005 was primarily due to an increase of $421.3 million related to the issuances of short-term borrowings and $19.6 million related to the reclassification of proceeds from derivative power sales contracts. These increases were partially offset by the absence of $308.5 million related to a customer contract restructuring, which had a positive impact in 2005. We discuss this customer contract restructuring in more detail in *Note 4* of our 2005 Annual Report on Form 10-K.

Security Ratings

Independent credit-rating agencies rate Constellation Energy's and BGE's fixed-income securities. The ratings indicate the agencies' assessment of each company's ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost each company to sell these securities; the better the rating, the lower the cost of the securities to each company when they sell them.

The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, and the amount of debt as a component of total capitalization.

In April 2006, as a result of regulatory and legislative developments in Maryland, Standard & Poors Rating Group, Moody's Investors Service, and Fitch Ratings reviewed our ratings and took the following actions:

- Fitch Ratings downgraded Constellation Energy's Senior Unsecured Debt rating from A- to BBB+, downgraded BGE's Senior Unsecured Debt ratings from A to A-, and reduced certain other credit ratings as noted in the table below.
- Fitch Ratings changed Constellation Energy's outlook to "evolving" and BGE's outlook to "negative."
- Moody's Investor Service downgraded BGE's Senior Unsecured Debt rating from A2 to A3, reduced certain other credit ratings as noted in the table below, and BGE's rating remains under review for further downgrade.
- Moody's Investor Service revised Constellation Energy's rating outlook from "positive" to "developing."
- Standard & Poor's Ratings Services placed the ratings on Constellation Energy and BGE on "creditwatch developing" from "positive."

At the date of this report, our credit ratings were as follows:

	Standard & Poors Rating Group	**Moody's Investors Service**	**Fitch-Ratings**

	Standard & Poors Rating Group	Moody's Investors Service	Fitch-Ratings
Constellation Energy			
Commercial Paper	A-2	P-2	F-2
Senior Unsecured Debt	BBB	Baa1	BBB+*
BGE			
Commercial Paper	A-2	P-2*	F-2*
Mortgage Bonds	A	A2*	A*
Senior Unsecured Debt	BBB+	A3*	A-*
Trust Preferred Securities	BBB-	Baa1*	BBB+*
Preference Stock	BBB-	Baa2*	BBB+*

** In April 2006, these credit ratings were reduced one level to this current rating.*

We discuss the regulatory developments in Maryland in the *Regulation by the Maryland PSC* section beginning on page 21.

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

At March 31, 2006, we had $425.0 million of commercial paper outstanding, and at May 5, 2006 we had $330.0 million of commercial paper outstanding.

Constellation Energy has committed bank lines of credit under four credit facilities of $3.6 billion at March 31, 2006 for short-term financial needs. We discuss these credit facilities in more detail in *Note 8* of our 2005 Annual Report on Form 10-K. These facilities can issue letters of credit up to approximately $3.6 billion. Letters of credit issued under all of our facilities totaled $1.9 billion at March 31, 2006.

BGE

BGE maintains $200.0 million in annual committed credit facilities, expiring May through November of 2006. BGE can borrow directly from the banks or use the facilities to allow commercial paper to be issued. As of March 31, 2006, 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 2006 and 2007 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 2006 and 2007 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 45 and *Item 1A. Risk Factors* section on page 44. We discuss the potential impact of environmental legislation and regulation in more detail in *Item 1. Business Environmental Matters* section of our 2005 Annual Report on Form 10-K. We discuss legislation recently enacted by the State of Maryland in the *Environmental Matters* section beginning on page 23.

Calendar Year Estimates	**2006**	**2007**
	(In millions)	
Nonregulated Capital Requirements:		
Merchant energy		
Generation plants	$ 220	$ 170
Nuclear fuel	140	140

Calendar Year Estimates	**2006**	**2007**
Environmental controls	40	215
Portfolio acquisitions/investments	330	195
Technology/other	250	155
Total merchant energy capital requirements	980	875
Other nonregulated capital requirements	20	10
Total nonregulated capital requirements	1,000	885
Regulated Capital Requirements:		
Regulated electric	300	335
Regulated gas	60	110
Total regulated capital requirements	360	445
Total capital requirements	$ 1,360	$ 1,330

Capital Requirements

Merchant Energy Business

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

- improvements to generating plants,
- nuclear fuel costs,
- upstream gas investments,
- portfolio acquisitions and other investments,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania regulations and legislation, and
- enhancements to our information technology infrastructure.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability.

Funding for Capital Requirements

We discuss our funding for capital requirements in our 2005 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 March 31, 2006, decreased approximately $450 million during the first quarter of 2006 primarily due to fulfilling gas commitments outstanding at December 31, 2005 during the first quarter of 2006. We detail our contractual payment obligations in the following table:

	Payments				
	2006	2007-2008	2009-2010	There-after	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 16.2	$ 627.5	$ 501.4	$ 2,240.1	$ 3,385.2
Interest	163.2	367.7	318.8	1,476.9	2,326.6
Total	179.4	995.2	820.2	3,717.0	5,711.8
BGE					
Principal	444.6	416.8	11.5	589.1	1,462.0
Interest	62.2	97.5	71.2	775.1	1,006.0
Total	506.8	514.3	82.7	1,364.2	2,468.0
BGE preference stock				190.0	190.0
Operating leases[2]	123.0	262.9	94.0	331.9	811.8
Purchase obligations:[3]					
Purchased capacity and energy[4]	518.0	966.4	361.6	320.6	2,166.6
Fuel and transportation	1,618.2	1,547.4	481.2	542.9	4,189.7
Other	100.8	132.1	44.4	144.5	421.8
Other noncurrent liabilities:					
Postretirement and postemployment benefits[5]	21.6	76.3	83.9	202.4	384.2
Other					
Total contractual payment obligations	$ 3,067.8	$ 4,494.6	$ 1,968.0	$ 6,813.5	$ 16,343.9

1 Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $282.3 million early through put options and remarketing features. Interest on variable rate debt is included based on the March 31, 2006 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 2005 Annual Report on Form 10-K.

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

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

5 Amounts related to 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 below presents our contingent obligations. Our contingent obligations decreased approximately $280 million during the first quarter of 2006, primarily due to decreased letters of credit of approximately $540 million by the parent company for subsidiary obligations to third parties, partially offset by increased guarantees of approximately $240 million for our competitive supply 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 $8,512.1 million of parent company guarantees was $2,513.3 million at March 31, 2006. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount based on March 31, 2006 market prices is $2,513.3 million.

	Expiration				
	2006	2007-2008	2009-2010	There-after	Total
	(In millions)				
Contingent Obligations					
Letters of credit	$ 1,636.7	$ 309.9	$	$	$ 1,946.6
Guarantees competitive supply[1]	5,417.9	989.0	245.0	1,860.2	8,512.1
Other guarantees, net[2]	5.3	13.5	1.7	1,251.2	1,271.7
Total contingent obligations	$ 7,059.9	$ 1,312.4	$ 246.7	$ 3,111.4	$ 11,730.4

1 While the face amount of these guarantees is $8,512.1 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 $2,513.3 million at March 31, 2006.

2 Other guarantees in the above table are shown net of liabilities of $25.0 million recorded at March 31, 2006 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 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 declined below established contractual levels. Based on contractual provisions at March 31, 2006, we estimate that if Constellation

Energy's senior unsecured debt were downgraded we would have the following additional collateral obligations:

Credit Ratings Downgraded to	Incremental Obligations	Cumulative Obligations
	(In millions)	
BBB-/Baa3	$ 151	$ 151
Below investment grade	1,073	1,224

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, which could be material. We discuss our credit ratings in the *Security Ratings* section on page 38 and our credit facilities in the *Available Sources of Funding* section beginning on page 38.

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 March 31, 2006, the debt to capitalization ratios as defined in the credit agreements were no greater than 62%. The failure by Constellation Energy to comply with these provisions could result in the acceleration of the maturity of the debt outstanding under these facilities, which is primarily letters of credit issued in support of our competitive supply operations. We detail our letters of credit in the *Contractual Payment Obligations and Committed Amounts* section on the previous page. This ratio can change significantly as a result of changes in outstanding letters of credit and accumulated other comprehensive income, which are both impacted by movements in commodity prices. We discuss the current market price environment in more detail in the *Events of 2006* section on page 24.

Certain credit facilities of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At March 31, 2006, the debt to capitalization ratio for BGE as defined in these credit agreements was 45%. At March 31, 2006, no amount is outstanding under these facilities.

Off-Balance Sheet Arrangements

We discuss our off-balance sheet arrangements in our 2005 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 2005 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.

The value at risk amounts in the tables below reflect the continued volatility of commodity prices and the increase in our trading activities. We discuss our mark-to-market results in more detail in the *Competitive Supply* section beginning on page 28.

	Quarter Ended March 31, 2006
	(In millions)
99% Confidence Level, One-Day Holding Period	
Average	$ 15.4
High	23.5

	Quarter Ended March 31, 2006
95% Confidence Level, One-Day Holding Period	
Average	11.7
High	17.9
95% Confidence Level, Ten-Day Holding Period	
Average	37.1
High	56.5

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 quarter of 2006:

	Quarter Ended March 31, 2006
	(In millions)
Average	$ 12.0
High	17.6

Due to the inherent limitations of statistical measures such as value at risk and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method.

As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Wholesale Credit Risk

We actively monitor the credit portfolio of our wholesale marketing and risk management operation to attempt to reduce the impact of counterparty default. As of March 31, 2006 and December 31, 2005, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings:

	March 31, 2006	**December 31, 2005**
Rating		
Investment Grade[1]	**55%**	53%
Non-Investment Grade	**7**	7
Not Rated	**38**	40

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

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

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

	March 31, 2006	**December 31, 2005**
Investment Grade Equivalent	**81%**	80%
Non-Investment Grade	**19**	20

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 March 31, 2006:

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	$ 1,066	$ 35	$ 1,031		$
Split rating	12		12		
Non-investment grade	160	58	102		
Internally rated investment grade	434	22	412		
Internally rated non-investment grade	166	4	162		
Total	$ 1,838	$ 119	$ 1,719		$

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 beginning on page 40.

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 2005 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 18,

activities of our wholesale marketing and risk management operation in the *Merchant Energy Business* section of *Management's Discussion and Analysis* beginning on page 25,

evaluation of commodity and credit risk in the *Market Risk* section of *Management's Discussion and Analysis* beginning on page 41, and

changes to our business environment in the *Business Environment* section of *Management's Discussion and Analysis* beginning on page 21.

Item 4. Controls and Procedures

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

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

Evaluation of Disclosure Controls and Procedures

The principal executive officers and principal financial officer of both Constellation Energy and BGE have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal quarter covered by this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's and BGE's disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2006, there has been no change in either Constellation Energy's or BGE's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d 15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, either Constellation Energy's or BGE's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We discuss our Legal Proceedings in the *Notes to Consolidated Financial Statements* beginning on page 17.

Item 1A. Risk Factors

The risk factors included in our 2005 Annual Report on Form 10-K have not materially changed except as set forth below. You should consider carefully the following risk, along with the risks described under Item 1A. Risk Factors in our 2005 Annual Report on Form 10-K. The risks and uncertainties described herein and in our 2005 Annual Report on Form 10-K are not the only ones that may affect us. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 2. Management's Discussion and Analysis. If any of the events described actually occur, our business and financial results could be materially adversely affected.

BGE may not be able to recover costs incurred in satisfying its provider of last resort (POLR) obligations, which may adversely affect our, or BGE's, financial results and liquidity

In March 2006, the Maryland Public Service Commission (Maryland PSC) approved a transition plan that would defer recovery of some of BGE's costs of providing residential electric service to address the significant increase in POLR prices that will take place upon the expiration of the residential rate freeze in June 2006. Under the plan, residential electric rates would increase incrementally until rates reach market-based levels in March 2007, and thereafter all deferred amounts would be recovered, including a financing charge at an annual rate of 5%.

In April 2006, the Maryland PSC approved an amended plan filed by BGE that will further defer the pending July 1, 2006 rate increase beyond the level originally ordered by the Maryland PSC and allow BGE to recover the deferral. Rates will not reach market-based levels until January 2008 for those customers who opt into the plan. Under either the original or the amended plan, BGE may have to finance any costs for which recovery from customers is deferred. If it cannot do so, or cannot do so on favorable terms, our, and BGE's, financial results and liquidity may be materially affected. BGE and another party have sought reconsideration and/or clarification of the order approving the amended plan from the Maryland PSC. Other parties could also seek reconsideration of the order approving the amended plan.

The City of Baltimore has sought judicial review of the Maryland PSC's order approving the amended plan as well as a stay to prevent BGE's implementation of the amended plan. If the stay is granted, BGE may be required to implement the original plan approved by the Maryland PSC in March 2006. We cannot predict whether a court will grant the requested stay, will reverse any aspect of the Maryland PSC's order, or will remand certain issues to the Maryland PSC for reconsideration. The outcome of the court proceeding, or the Maryland PSC rehearing, could have a material impact on our, and BGE's, financial results or liquidity.

There is also a possibility that the Maryland General Assembly will enact a plan that would preempt the Maryland PSC plan. The Maryland General Assembly considered a number of bills during its 2006 legislative session that would have extended rate caps, limited BGE's ability to recover its costs, or otherwise interfered in the regulatory process. However, none were enacted into law before the 2006 legislative session ended. The Maryland General Assembly may reintroduce similar bills in future regularly scheduled or special legislative sessions, which may be enacted into law. If another plan is enacted into law that would extend rate caps, expand the deferral period or not allow BGE to fully recover its costs, it could have a material impact on our, and BGE's, financial results and liquidity.

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
January 1 January 31, 2006	599	$ 58.22		
February 1 February 28, 2006	62,741	58.78		
March 1 March 31, 2006	3,350	58.82		
Total	66,690	$ 58.78		

Item 5. Other Information

Forward Looking Statements

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

the timing and extent of changes in commodity prices and volatilities for energy and energy related products including coal, natural gas, oil, electricity, nuclear fuel, and emission allowances,

the liquidity and competitiveness of wholesale markets for energy commodities,

the effect of weather and general economic and business conditions on energy supply, demand, and prices,

the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,

the timing and extent of deregulation of, and competition in, the energy markets, and the rules and regulations adopted in those markets,

uncertainties associated with estimating natural gas reserves, developing properties, and extracting natural gas,

regulatory or legislative developments that affect deregulation, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,

the inability of Baltimore Gas and Electric Company (BGE) to recover all its costs associated with providing electric residential customers service during or after the electric rate freeze period,

the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and BGE's ability to maintain their current credit ratings, the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,

operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control, the actual outcome of uncertainties associated with assumptions and estimates using judgment when applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and, in the absence of verifiable market prices, the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),

changes in accounting principles or practices,

losses on the sale or write down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets,

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

the likelihood and timing of the completion of the pending merger with FPL Group, Inc. (FPL Group), the terms and conditions of any required regulatory approvals of the pending merger, and potential diversion of management's time and attention from our ongoing business during this time period.

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

Changes may occur after that date, and neither Constellation Energy nor BGE 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: May 9, 2006

/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