CONSTELLATION ENERGY GROUP INC
Form 10-Q/A
July 30, 2003

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A
(Amendment No. 1)

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

For the quarterly period ended **MARCH 31, 2003**

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)

410-234-5000

(Registrants' telephone number, including area code)

NOT APPLICABLE

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

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

Indicate by check mark whether Constellation Energy Group, Inc. is an accelerated filer Yes ý No o

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

COMMON STOCK, WITHOUT PAR VALUE 165,335,362 SHARES OUTSTANDING OF CONSTELLATION ENERGY GROUP, INC. ON APRIL 30, 2003.

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.

Explanatory Note

Subsequent to the filing of our Quarterly Report on Form 10-Q for the period ended March 31, 2003, we discovered an overstatement of $282.9 million in revenues and expenses resulting from a change in our processes in anticipation of a market design change in New England. Accordingly, we are filing this amendment to restate certain parts of the Quarterly Report on Form 10-Q for Constellation Energy Group, Inc. and Baltimore Gas and Electric Company for the period ended March 31, 2003. As noted below, this amendment does not affect previously reported income from operations, earnings, cash flows or common shareholders' equity, nor does it affect revenues or expenses for any period other than the quarter ended March 31, 2003. This amendment affects only Part I Items 1, 2 and 4 of the previously filed Quarterly Report on Form 10-Q.

During the first quarter of 2003, in preparation for and following the implementation of changes in the market design in New England, our merchant energy business recorded certain transactions with the New England Independent System Operator (ISO) by computing gross sales and gross purchases by delivery location. This means that when our sources of power and ultimate load-serving customers were in different New England delivery locations, we recorded the transactions as a purchase from the third-party power provider in the source location and a sale to the New England ISO in that location. Then in the zone where our ultimate load-serving customer was served, we recorded a purchase from the New England ISO and a sale to the ultimate load-serving customer in that location. This gross reporting was consistent with the market design change in New England and ensured the appropriate capture of congestion and other costs in our systems necessary for risk management and settlement purposes. The New England ISO is however not a principal in these transactions; and as such, for financial reporting purposes we should have recorded these transactions on a net basis for the New England region as a whole and not on a gross basis.

As a result, we have restated our unaudited Consolidated Financial Statements for the period ended March 31, 2003, and made corresponding amendments to *Management's Discussion and Analysis of Financial Condition and Results of Operations*. The restatement has resulted in a reduction to both "Nonregulated revenues" and "Operating expenses" of $282.9 million for the period ended March 31, 2003. The principal effects of the restatement on the accompanying unaudited Consolidated Financial Statements are described in the *Notes to the Consolidated Financial Statements* beginning on page 9.

Please note that this amended Quarterly Report on Form 10-Q for the period ended March 31, 2003, does not reflect events occurring after May 14, 2003, the date on which we originally filed our Quarterly Report on Form 10-Q for the period ended March 31, 2003. For a description of these events, please read our reports filed with the Securities and Exchange Commission since May 14, 2003.

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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,

	2003	2002
	(Restated)	
	(In millions, except per share amounts)	
Revenues		
Nonregulated revenues	**$ 1,545.5**	$ 371.2
Regulated electric revenues	**486.3**	460.3
Regulated gas revenues	**298.2**	220.8
Total revenues	**2,330.0**	1,052.3
Expenses		
Operating expenses	**1,973.5**	682.2
Workforce reduction costs	**0.7**	25.9
Depreciation and amortization	**111.1**	117.1
Accretion of asset retirement obligations	**10.7**	
Taxes other than income taxes	**72.1**	65.6
Total expenses	**2,168.1**	890.8

Three Months Ended March 31,

	2003	2002
Net Gain on Sales of Investments and Other Assets	**13.7**	257.1
Income from Operations	**175.6**	418.6
Other Income	**8.9**	4.5
Fixed Charges		
Interest expense	**82.3**	67.9
Interest capitalized and allowance for borrowed funds used during construction	**(4.4)**	(11.8)
BGE preference stock dividends	**3.3**	3.3
Total fixed charges	**81.2**	59.4
Income Before Income Taxes	**103.3**	363.7
Income Taxes	**36.3**	135.1
Income Before Cumulative Effects of Changes in Accounting Principles	**67.0**	228.6
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes of $119.5	**(198.4)**	
Net (Loss) Income	**$ (131.4)**	$ 228.6
(Loss) Earnings Applicable to Common Stock	**$ (131.4)**	$ 228.6
Average Shares of Common Stock Outstanding	**164.9**	163.7
Earnings Per Common Share and Earnings Per Common Share Assuming Dilution Before Cumulative Effects of Changes in Accounting Principles	**$ 0.40**	$ 1.40
Cumulative Effects of Changes in Accounting Principles	**(1.20)**	
(Loss) Earnings Per Common Share and (Loss) Earnings Per Common Share Assuming Dilution	**$ (0.80)**	$ 1.40
Dividends Declared Per Common Share	**$ 0.26**	$ 0.24

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,

	2003	2002
	(In millions)	
Net (Loss) Income	**$ (131.4)**	$ 228.6
Other comprehensive income (OCI)		
Reclassification of net gain on sales of securities from OCI to net income, net of taxes	**(2.6)**	(156.9)
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes	**(6.0)**	(3.7)

Three Months Ended March 31,	2003	2002
Net unrealized loss on hedging instruments, net of taxes	**(6.0)**	(37.1)
Net unrealized loss on securities, net of taxes	**(11.7)**	(4.9)
Comprehensive (Loss) Income	**$ (157.7)**	$ 26.0

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

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	March 31, 2003*	***December 31, 2002***
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 612.2**	$ 615.0
Accounts receivable (net of allowance for uncollectibles of **$45.1** and $41.9 respectively)	**1,799.4**	1,244.1
Trading securities	**9.3**	77.1
Mark-to-market energy assets	**114.8**	144.0
Risk management assets	**217.7**	72.3
Fuel stocks	**84.1**	126.5
Materials and supplies	**199.1**	208.6
Prepaid taxes other than income taxes	**41.8**	57.1
Other	**197.9**	157.1
Total current assets	**3,276.3**	2,701.8
Investments and Other Assets		
Real estate projects and investments	**72.5**	86.1
Investments in qualifying facilities and power projects	**436.0**	439.2
Financial investments	**28.4**	36.9
Nuclear decommissioning trust funds	**631.3**	645.4
Mark-to-market energy assets	**1,027.0**	1,348.2
Risk management assets	**59.7**	88.8
Goodwill	**121.1**	115.9
Other	**194.0**	167.8
Total investments and other assets	**2,570.0**	2,928.3

	March 31, 2003*		December 31, 2002
Property, Plant and Equipment			
Regulated property, plant and equipment		**5,100.9**	5,075.2
Nonregulated generation property, plant and equipment		**6,994.4**	6,811.9
Other nonregulated property, plant and equipment		**257.0**	242.0
Nuclear fuel (net of amortization)		**211.5**	224.8
Accumulated depreciation		**(3,781.2)**	(4,396.8)
Net property, plant and equipment		**8,782.6**	7,957.1
Deferred Charges			
Regulatory assets (net)		**301.0**	405.7
Other		**133.4**	136.0
Total deferred charges		**434.4**	541.7
Total Assets	**$**	**15,063.3**	$ 14,128.9

** Unaudited*

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

	March 31, 2003*		December 31, 2002
		(In millions)	
Liabilities and Equity			
Current Liabilities			
Short-term borrowings	**$**	**12.4**	$ 10.5
Current portion of long-term debt		**291.6**	426.2
Accounts payable		**1,373.7**	943.4
Customer deposits and collateral		**356.4**	102.8
Mark-to-market energy liabilities		**106.4**	94.1
Risk management liabilities		**169.6**	20.1
Accrued interest		**128.1**	95.5
Dividends declared		**46.2**	42.8
Other		**288.5**	337.1
Total current liabilities		**2,772.9**	2,072.5

	March 31, 2003*	December 31, 2002
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,217.8**	1,330.7
Mark-to-market energy liabilities	**951.8**	881.5
Risk management liabilities	**153.8**	149.5
Asset retirement obligations	**581.3**	
Net pension liability	**230.9**	334.6
Postretirement and postemployment benefits	**357.7**	352.8
Deferred investment tax credits	**83.9**	85.7
Other	**135.5**	150.1
Total deferred credits and other liabilities	**3,712.7**	3,284.9
Long-term Debt		
Long-term debt of Constellation Energy	**2,800.0**	2,800.0
Long-term debt of nonregulated businesses	**348.3**	349.8
First refunding mortgage bonds of BGE	**780.1**	904.9
Other long-term debt of BGE	**735.1**	745.1
Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE due June 30, 2038	**250.0**	250.0
Unamortized discount and premium	**(9.2)**	(9.7)
Current portion of long-term debt	**(291.6)**	(426.2)
Total long-term debt	**4,612.7**	4,613.9
Minority Interests	**107.0**	105.3
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock	**2,086.4**	2,078.9
Retained earnings	**1,802.1**	1,977.6
Accumulated other comprehensive loss	**(220.5)**	(194.2)
Total common shareholders' equity	**3,668.0**	3,862.3
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 15,063.3**	$ 14,128.9

** Unaudited*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Constellation Energy Group, Inc. and Subsidiaries

Three Months Ended March 31,	**2003**	**2002**
	(In millions)	
Cash Flows From Operating Activities		
Net (loss) income	**$ (131.4)**	$ 228.6
Adjustments to reconcile to net cash provided by operating activities		
Cumulative effects of changes in accounting principles	**198.4**	
Depreciation and amortization	**139.4**	124.5
Accretion of asset retirement obligations	**10.7**	
Deferred income taxes	**30.5**	(23.9)
Investment tax credit adjustments	**(1.8)**	(2.0)
Deferred fuel costs	**(24.9)**	25.5
Pension and postemployment benefits	**(98.1)**	(27.7)
Net gain on sales of investments and other assets	**(13.7)**	(257.1)
Workforce reduction costs	**0.7**	25.9
Equity in earnings of affiliates less than dividends received	**8.7**	26.4
Changes in		
Accounts receivable	**(559.3)**	(143.2)
Mark-to-market energy assets and liabilities	**47.2**	53.3
Risk management assets and liabilities	**(15.1)**	(23.8)
Materials, supplies and fuel stocks	**51.9**	35.3
Other current assets	**(27.0)**	101.3
Accounts payable	**366.2**	224.7
Other current liabilities	**232.2**	136.8
Other	**31.1**	(69.7)
Net cash provided by operating activities	**245.7**	434.9
Cash Flows From Investing Activities		
Purchases of property, plant and equipment	**(148.1)**	(226.5)
Contributions to nuclear decommissioning trust funds	**(4.4)**	(0.2)
Sales of investments and other assets	**89.8**	591.0
Other investments	**(21.9)**	(2.1)
Net cash (used in) provided by investing activities	**(84.6)**	362.2
Cash Flows From Financing Activities		
Net issuance (maturity) of short-term borrowings	**1.9**	(775.8)
Proceeds from issuance of		
Long-term debt		1,821.0
Common stock	**10.1**	

Three Months Ended March 31,	2003	2002
Repayment of long-term debt	**(134.9)**	(848.5)
Common stock dividends paid	**(39.6)**	(19.7)
Other	**(1.4)**	(4.4)
Net cash (used in) provided by financing activities	**(163.9)**	172.6
Net (Decrease) Increase in Cash and Cash Equivalents	**(2.8)**	969.7
Cash and Cash Equivalents at Beginning of Period	**615.0**	72.4
Cash and Cash Equivalents at End of Period	**$ 612.2**	$ 1,042.1

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

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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Three Months Ended March 31,	2003	2002
	(In millions)	
Revenues		
Electric revenues	**$ 486.3**	$ 460.4
Gas revenues	**303.5**	223.3
Total revenues	**789.8**	683.7
Expenses		
Operating expenses		
Electricity purchased for resale	**243.6**	240.5
Gas purchased for resale	**203.1**	124.3
Operations and maintenance	**77.1**	84.5
Workforce reduction costs	**0.3**	20.9
Depreciation and amortization	**55.9**	56.5
Taxes other than income taxes	**45.2**	44.0
Total expenses	**625.2**	570.7
Income from Operations	**164.6**	113.0
Other Income	**0.3**	1.3
Fixed Charges		
Interest expense	**30.0**	36.5
Allowance for borrowed funds used during construction	**(0.5)**	(0.4)
Total fixed charges	**29.5**	36.1

Three Months Ended March 31,	2003	2002
Income Before Income Taxes	**135.4**	78.2
Income Taxes	**53.6**	31.0
Net Income	**81.8**	47.2
Preference Stock Dividends	**3.3**	3.3
Earnings Applicable to Common Stock	**$ 78.5**	$ 43.9

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, **2003***	*December 31,* **2002**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 9.1**	$ 10.2
Accounts receivable (net of allowance for uncollectibles of **$11.5** and $11.5, respectively)	**391.3**	357.5
Investment in cash pool, affiliated company	**338.7**	338.1
Accounts receivable, affiliated companies	**82.5**	131.2
Fuel stocks	**14.4**	40.6
Materials and supplies	**34.3**	31.8
Prepaid taxes other than income taxes	**21.0**	42.0
Other	**10.9**	10.3
Total current assets	**902.2**	961.7
Other Assets		
Receivable, affiliated company	**139.7**	63.3
Other	**85.7**	85.9
Total other assets	**225.4**	149.2
Utility Plant		
Plant in service		
Electric	**3,457.4**	3,422.3

	March 31, 2003*	December 31, 2002
Gas	**1,046.3**	1,041.0
Common	**483.9**	489.1
Total plant in service	**4,987.6**	4,952.4
Accumulated depreciation	**(1,777.4)**	(1,851.4)
Net plant in service	**3,210.2**	3,101.0
Construction work in progress	**108.8**	118.3
Plant held for future use	**4.5**	4.5
Net utility plant	**3,323.5**	3,223.8
Deferred Charges		
Regulatory assets (net)	**301.0**	405.7
Other	**44.4**	39.5
Total deferred charges	**345.4**	445.2
Total Assets	**$ 4,796.5**	$ 4,779.9

** Unaudited*

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

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

	March 31, 2003*	December 31, 2002
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 285.9**	$ 420.7
Accounts payable	**125.8**	103.2
Accounts payable, affiliated companies	**71.6**	85.6
Customer deposits	**56.0**	54.2
Accrued taxes	**53.1**	9.0
Accrued interest	**34.1**	31.4
Other	**46.2**	49.7
Total current liabilities	**672.7**	753.8

	*March 31, 2003**	*December 31, 2002*
Deferred Credits and Other Liabilities		
Deferred income taxes	**546.1**	528.9
Postretirement and postemployment benefits	**280.1**	278.0
Deferred investment tax credits	**20.0**	20.5
Decommissioning of federal uranium enrichment facilities	**14.6**	14.6
Other	**14.1**	13.9
Total deferred credits and other liabilities	**874.9**	855.9
Long-term Debt		
First refunding mortgage bonds of BGE	**780.1**	904.9
Other long-term debt of BGE	**735.1**	745.1
Company obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE due June 30, 2038	**250.0**	250.0
Long-term debt of nonregulated businesses	**25.0**	25.0
Unamortized discount and premium	**(4.8)**	(5.2)
Current portion of long-term debt	**(285.9)**	(420.7)
Total long-term debt	**1,499.5**	1,499.1
Minority Interest	**19.2**	19.4
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**628.0**	549.5
Total common shareholder's equity	**1,540.2**	1,461.7
Commitments, Guarantees, and Contingencies (see Notes)		
Total Liabilities and Equity	**$ 4,796.5**	$ 4,779.9

** Unaudited*

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Baltimore Gas and Electric Company and Subsidiaries

Three Months Ended March 31,	**2003**	2002
	(In millions)	
Cash Flows From Operating Activities		
Net income	**$ 81.8**	$ 47.2
Adjustments to reconcile to net cash provided by operating activities		
Depreciation and amortization	**56.7**	57.2
Deferred income taxes	**17.6**	(15.4)
Investment tax credit adjustments	**(0.5)**	(0.5)
Deferred fuel costs	**(24.9)**	25.5
Pension and postemployment benefits	**(73.5)**	6.8
Workforce reduction costs	**0.3**	20.9
Allowance for equity funds used during construction	**(0.9)**	(0.7)
Changes in		
Accounts receivable	**(33.8)**	(38.9)
Receivables, affiliated companies	**(27.7)**	86.9
Materials, supplies, and fuel stocks	**23.7**	38.3
Other current assets	**20.4**	49.9
Accounts payable	**22.6**	(6.0)
Accounts payable, affiliated companies	**(14.0)**	(19.0)
Other current liabilities	**45.1**	37.0
Other	**88.5**	(17.7)
Net cash provided by operating activities	**181.4**	271.5
Cash Flows From Investing Activities		
Utility construction expenditures (excluding AFC)	**(43.8)**	(40.1)
Investment in cash pool at parent	**(0.6)**	(24.6)
Other		(3.8)
Net cash used in investing activities	**(44.4)**	(68.5)
Cash Flows From Financing Activities		
Repayment of long-term debt	**(134.8)**	(213.0)
Preference stock dividends paid	**(3.3)**	(3.3)
Net cash used in financing activities	**(138.1)**	(216.3)
Net Decrease in Cash and Cash Equivalents	**(1.1)**	(13.3)
Cash and Cash Equivalents at Beginning of Period	**10.2**	37.4
Cash and Cash Equivalents at End of Period	**$ 9.1**	$ 24.1

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

Basis of Presentation

This Quarterly Report on Form 10-Q is a combined report of Constellation Energy 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 "utility business" are to BGE.

Effects of Restatement on Interim Financial Statements

During the first quarter of 2003, in preparation for and following the implementation of changes in the market design in New England, our merchant energy business recorded certain transactions with the New England Independent System Operator (ISO) by computing gross sales and gross purchases by delivery location. This means that when our sources of power and ultimate load-serving customers were in different New England delivery locations, we recorded the transactions as a purchase from the third-party power provider in the source location and a sale to the New England ISO in that location. Then in the zone where our ultimate load-serving customer was served, we recorded a purchase from the New England ISO and a sale to the ultimate load-serving customer in that location. This gross reporting was consistent with the market design change in New England and ensured the appropriate capture of congestion and other costs in our systems necessary for risk management and settlement purposes. The New England ISO is however not a principal in these transactions; and as such, for financial reporting purposes we should have recorded these transactions on a net basis for the New England region as a whole and not on a gross basis.

As a result, we have restated our unaudited Consolidated Financial Statements for the quarter ended March 31, 2003, from amounts previously reported. The restatement has resulted in a reduction to "Nonregulated revenues" and "Operating expenses" of $282.9 million for the quarter ended March 31, 2003. The restatement does not affect income from operations, earnings, cash flows or common shareholders' equity, nor does it affect revenues or expenses for any period other than the quarter ended March 31, 2003. A summary of the effects of the change from accounting for these transactions on a gross basis to a net basis for the quarter ended March 31, 2003 on our unaudited Consolidated Statements of Income is as follows:

Three Months Ended March 31, 2003

	As Previously Reported	Adjustment	Restated
		(In millions)	
Revenues			
Nonregulated revenues	$ 1,828.4	$ (282.9)	$ 1,545.5
Regulated electric revenues	486.3		486.3
Regulated gas revenues	298.2		298.2
Total revenues	2,612.9	(282.9)	2,330.0
Expenses			
	2,256.4	(282.9)	1,973.5

Three Months Ended March 31, 2003

Operating expenses			
Workforce reduction costs	0.7		0.7
Depreciation and amortization	111.1		111.1
Accretion of asset retirement obligations	10.7		10.7
Taxes other than income taxes	72.1		72.1
Total expenses	2,451.0	(282.9)	2,168.1
Net Gain on Sales of Investments and Other Assets	13.7		13.7
Income from Operations	$ 175.6	$	$ 175.6
Income Before Cumulative Effects of Changes in Accounting Principles	$ 67.0	$	$ 67.0
Cumulative Effects of Changes in Accounting Principles	(198.4)		(198.4)
Net Loss	$ (131.4)	$	$ (131.4)
Loss Applicable to Common Stock	$ (131.4)	$	$ (131.4)

The effects of the adjustment on the Merchant Energy Business segment are as follows:

Three Months Ended March 31, 2003

	As Previously Reported	Adjustment	Restated
		(in millions)	
Unaffiliated revenues	$ 1,672.8	$ (282.9)	$ 1,389.9
Intersegment revenues	287.2		287.2
Total revenues	1,960.0	(282.9)	1,677.1
Loss from operations	(10.0)		(10.0)

Three Months Ended March 31, 2003

Cumulative effects of changes in accounting principles	(198.4)	(198.4)
Net loss	(218.9)	(218.9)

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. Stock options to purchase approximately 5.0 million shares during the quarter ended March 31, 2003 and approximately 1.5 million shares during the quarter ended March 31, 2002 were not dilutive and were excluded from the computation of diluted EPS for those periods.

Stock-Based Compensation

Under our long-term incentive plans, we granted stock options, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. As permitted by Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, we measure our stock-based compensation using the intrinsic value method in accordance with Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. We discuss these plans and accounting further in *Note 13* of our 2002 Annual Report on Form 10-K.

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

Quarter Ended March 31,

	2003	**2002**
	(In millions, except per share amounts)	
Net (loss) income, as reported	**$ (131.4)**	$ 228.6
Add: Stock-based compensation expense determined under intrinsic value method and included in reported net (loss) income, net of related tax effects	**0.9**	0.4
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	**(3.0)**	(1.7)
Pro-forma net (loss) income	**$ (133.5)**	$ 227.3
(Loss) earnings per share:		
Basic as reported	**$ (.80)**	$ 1.40
Basic pro forma	**$ (.81)**	$ 1.39
Diluted as reported	**$ (.80)**	$ 1.40
Diluted pro forma	**$ (.81)**	$ 1.39

Workforce Reduction Costs

We incurred costs related to workforce reduction efforts initiated in previous years. We discuss these costs in more detail below and in *Note 2* of our 2002 Annual Report on Form 10-K.

2003

We recorded $0.7 million in expense, of which BGE recorded $0.3 million, associated with deferred payments to employees eligible for the 2001 Voluntary Special Early Retirement Program.

2002

In the first quarter of 2002, we recorded $35.1 million of net workforce reduction costs associated with our 2001 workforce reduction initiatives. The $35.1 million of net workforce reduction costs recorded during the first quarter of 2002 consisted of $25.9 million recognized as expense, of which BGE recognized $20.9 million. The remaining $9.2 million was recognized by BGE as a regulatory asset related to its gas business.

In 2002, we completed involuntary severances under the 2001 workforce reduction programs. Accordingly, no involuntary severance liability recorded under EITF 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring),* remained at December 31, 2002.

In 2002, we recorded $14.9 million of expenses for anticipated involuntary severance costs in accordance with EITF 94-3 associated with new workforce reduction initiatives in that year. The following table summarizes the status of the involuntary severance liability recorded under EITF 94-3.

	(In millions)	
Severance liability balance at December 31, 2002	$	14.9
Cash severance payments		(10.5)
Severance liability balance at March 31, 2003	$	4.4

Net Gain on Sales of Investments and Other Assets

2003

During the first quarter of 2003, our other nonregulated businesses recognized $13.7 million pre-tax, or $8.3 million after-tax, gains on the sale of non-core assets as follows:

- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and
- a $1.2 million pre-tax gain on an installment sale of a parcel of real estate.

2002

During the first quarter of 2002, our other nonregulated businesses recognized $257.1 million on the sale of financial investments, including the gain on the sale of our investment in Orion Power Holdings, Inc. (Orion). In February 2002, Reliant Resources, Inc. acquired all of the outstanding shares of Orion for $26.80 per share, including the shares of Orion we owned. We received cash proceeds of $454.1 million and recognized a gain of $255.5 million pre-tax, or $163.3 million after-tax, on the sale of our investment.

Information by Operating Segment

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

Our nonregulated merchant energy business in North America includes:

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

origination of structured transactions (such as load-serving, tolling contracts, and power purchase agreements), and risk management services to various customers (including hedging of output from generating facilities and fuel costs),

electric and gas retail energy services to large commercial and industrial customers, and

generation and consulting services.

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

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

Our remaining nonregulated businesses:

design, construct, and operate single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,

service electric and gas appliances, and heating and air conditioning systems, engage in home improvements, and sell electricity and natural gas, and

own and operate a district cooling system for commercial customers.

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American power distribution project and in a fund that holds interests in two South American energy projects.

These 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 on the next page.

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	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Unallocated Corporate Items and Eliminations	Consolidated
For the three months ended March 31,						
				(In millions)		
2003 *(Restated)*						
Unaffiliated revenues	**$ 1,389.9**	**$ 486.3**	**$ 298.2**	**$ 155.6**	**$**	**$ 2,330.0**
Intersegment revenues	**287.2**		**5.3**		**(292.5)**	
Total revenues	**1,677.1**	**486.3**	**303.5**	**155.6**	**(292.5)**	**2,330.0**
(Loss) income from operations	**(10.0)**	**109.0**	**55.6**	**21.0**		**175.6**

	Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Unallocated Corporate Items and Eliminations	Consolidated
Cumulative effects of changes in accounting principles	**(198.4)**					**(198.4)**
Net (loss) income	**(218.9)**	**50.2**	**28.6**	**8.7**		**(131.4)**
2002						
Unaffiliated revenues	$ 250.8	$ 460.3	$ 220.8	$ 120.4	$	$ 1,052.3
Intersegment revenues	239.2	0.1	2.5		(241.8)	
Total revenues	490.0	460.4	223.3	120.4	(241.8)	1,052.3
Income from operations	49.4	59.7	53.3	256.2		418.6
Net income	27.0	16.4	27.8	157.4		228.6

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

Commitments, Guarantees, and Contingencies

Our merchant energy business enters into long-term contracts for:

- the purchase of electric generating capacity and energy,
- the procurement and delivery of fuels to supply our generating plant requirements,
- the capacity and transmission rights for the physical delivery of energy to meet our obligations to our customers, and
- other capital requirements.

Our regulated gas business enters into various long-term contracts for the procurement, transportation, and storage of gas.

BGE Home Products & Services also has gas and electric purchase commitments related to sales programs which expire in 2004.

At March 31, 2003, the total amount of commitments was $4,082.2 million, which are primarily related to our merchant energy business.

Long-Term Power Sales Contracts

We entered into long-term power sales contracts in connection with our load-serving activities. We also entered into long-term power sales contracts associated with certain of our power plants. Our load-serving power sales contracts extend for terms through 2012 and provide for the sale of full requirements energy to electricity distribution utilities and certain retail customers. Our power sales contracts associated with our power plants extend for terms into 2011 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:

Payments/Expiration				
2003	2004-2005	2006-2007	Thereafter	Total
(In millions)				

	Payments/Expiration				
Competitive Supply	$ 2,345.3	$ 232.6	$ 40.8	$ 178.8	$ 2,797.5
Other	5.2	6.6	602.9	517.3	1,132.0
Total	$ 2,350.5	$ 239.2	$ 643.7	$ 696.1	$ 3,929.5

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At March 31, 2003, Constellation Energy had a total of $3,929.5 million in guarantees outstanding related to loans, credit facilities, and contractual performance of certain of its subsidiaries as described below. These guarantees do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent guarantees from one Constellation entity for another. We do not expect to fund the full amount under these guarantees.

Constellation Energy guaranteed $2,797.5 million on behalf of its subsidiaries for competitive supply activities. These guarantees are put into place in order to allow the subsidiaries the flexibility needed to conduct business with counterparties without having to post substantial cash collateral. While the face amount of these guarantees is $2,797.5 million, we do not expect to fund the full amount as our calculated fair value of obligations covered by these guarantees was $812.7 million at March 31, 2003. The recorded fair value of obligations in our Consolidated Balance Sheets for these guarantees was $560.6 million at March 31, 2003.

Constellation Energy guaranteed $206.6 million primarily on behalf of Nine Mile Point related to nuclear decommissioning.

Constellation Energy guaranteed $54.4 million on behalf of our other nonregulated businesses primarily for loans and performance bonds of which $25.6 million was recorded in our Consolidated Balance Sheets at March 31, 2003.

Constellation Energy guaranteed up to $600.0 million relating to the High Desert project. This amount is included in the "Other" guarantees for 2006 in the preceding table.

Our merchant energy business guaranteed $7.7 million for loans related to certain power projects in which we have an investment.

BGE guaranteed two-thirds of certain debt of Safe Harbor Water Power Corporation, an unconsolidated investment. At March 31, 2003, 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 Originated Preferred Securities (TOPrS) of $250.0 million. We discuss TOPrS in more detail in our 2002 Annual Report on Form 10-K.

The total fair value of the obligations for our guarantees recorded in our Consolidated Balance Sheets was $836.2 million and not the $3,929.5 million of total guarantees. We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

We are subject to regulation by various federal, state and local authorities with regard to:

- air quality,
- water quality, and
- disposal of hazardous substances.

As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation, as required.

We discuss the significant matters below.

Clean Air

The Clean Air Act affects both existing generating facilities and new projects. The Clean Air Act and many state laws impose significant requirements relating to emissions of SO_2 (sulfur dioxide), NOx (nitrogen oxide), particulate matter, and other pollutants that result from burning fossil fuels. The Clean Air Act also contains other provisions that could materially affect some of our projects. Various provisions may require permits, inspections, or installation of additional pollution control technology or may require the purchase of emission allowances.

Certain of these provisions are described in more detail below.

On October 27, 1998, the Environmental Protection Agency (EPA) issued a rule requiring 22 Eastern states and the District of Columbia to reduce emissions of NOx. The EPA rule requires states to implement controls sufficient to meet their NOx budget by May 30, 2004. However, the Northeast states decided to require compliance in 2003. Coal-fired power plants are a principal target of NOx reductions under this initiative.

Many of our generation facilities are subject to NOx reduction requirements under the EPA rule, including those located in Maryland and Pennsylvania. At the Brandon Shores and Wagner facilities, we installed emission reduction equipment to meet Maryland regulations issued pursuant to EPA's rule. The owners of the Keystone plant in Pennsylvania are installing emissions reduction equipment by July 2003 to meet Pennsylvania regulations issued pursuant to EPA's rule. We estimate our costs for the equipment needed at this plant will be approximately $35 million. Through March 31, 2003, we have spent approximately $32 million.

The EPA established new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment that were upheld after various court appeals. While these standards may require increased controls at some of our fossil generating plants in the future, implementation could be delayed for several years. We cannot estimate the cost of these increased controls at this time because the states, including Maryland, Pennsylvania, and California, still need to determine what reductions in pollutants will be necessary to meet the EPA standards.

The EPA and several states filed suits against a number of coal-fired power plants in Mid-Western and Southern states alleging violations of the Prevention of Significant Deterioration and non-attainment provisions of the Clean Air Act's new source review requirements. The EPA requested information relating to modifications made to our Brandon Shores, Crane, and Wagner plants in Baltimore, Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants. We have responded to the EPA, and as of the date of this report the EPA has taken no further action.

Based on the levels of emissions control that the EPA and states are seeking in these new source review enforcement actions, we believe that material additional costs and penalties could be incurred, and planned capital expenditures could be accelerated, if the EPA was successful in any future actions regarding our facilities.

The Clean Air Act requires the EPA to evaluate the public health impacts of emissions of mercury, a hazardous air pollutant, from coal-fired plants. The EPA decided to control mercury emissions from coal-fired plants. Compliance could be required by approximately 2007. We believe final regulations could be issued in 2004 and would affect all coal-fired boilers. The cost of compliance with the final regulations could be material.

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies by plant type. Fossil fuel-fired power plants are significant sources of carbon dioxide emissions, a principal greenhouse gas. Our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Clean Water Act

Our facilities are subject to a variety of federal and state regulations governing existing and potential water/wastewater and stormwater discharges.

In April 2002, the EPA proposed rules under the Clean Water Act that require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. A final action on the proposed rules is expected by February 2004. The proposed rule may require the installation of additional intake screens or other protective measures, as well as extensive site-specific study and monitoring requirements. There is also the possibility that the proposed rules may lead to the installation of cooling towers on four of our fossil and both of our nuclear facilities. Our compliance costs associated with the final rules could be material.

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the cleanup of certain environmentally contaminated sites owned and operated by others. We cannot estimate the cleanup costs for all of these sites.

However, based on a Record of Decision issued by the EPA in 1997, we can estimate that BGE's current 15.47% share of the reasonably possible cleanup costs at one of these sites, Metal Bank of America, a metal reclaimer in Philadelphia, could be as much as $1.3 million higher than amounts we believe are probable and have recorded as a liability in our Consolidated Balance Sheets. There has been no significant activity with respect to this site since the EPA's Record of Decision in 1997.

In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Comprehensive Environmental Response, Compensation and Liability Act ("Superfund") National Priorities List ("NPL") and sent a general notice letter to BGE and 19 other parties identifying them as potentially liable parties at the 68th Street Dump site. In April 2003, EPA re-proposed the 68th Street site to the NPL, EPA's list of sites targeted for cleanup and enforcement. At this stage, it is not possible to predict the cleanup cost of the site or BGE's share of the liability, but the costs could be material.

In late December 1996, BGE signed a consent order with the Maryland Department of the Environment that required 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, the costs BGE considers to be probable to remedy the contamination are estimated to total $47 million. BGE recorded these costs as a liability on its Consolidated Balance Sheets and deferred these costs, net of accumulated amortization and amounts it recovered from insurance companies, as a regulatory asset. Because of the results of studies at this site, it is reasonably possible that additional costs could exceed the amount BGE recognized by approximately $14 million. Through March 31, 2003, BGE spent approximately $39 million for remediation at this site. BGE also investigated other small sites where gas was manufactured in the past. We do not expect the cleanup costs of the remaining smaller sites to have a material effect on our financial results.

Nuclear Insurance

We maintain nuclear insurance coverage for Calvert Cliffs and Nine Mile Point in four program areas: liability, worker radiation, property, and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war. We discuss our insurance programs in *Note 11* of our 2002 Annual Report on Form 10-K.

Non-nuclear Insurance

Our conventional property insurance provides coverage of $1.0 billion per occurrence for Certified acts of terrorism as defined under the Terrorism Risk Insurance Act. Certified acts of terrorism are determined by the Secretary of State and Attorney General of the United States and primarily are based upon the occurrence of significant acts of international terrorism.

An industry mutual insurance program covered losses resulting from non-certified acts of terrorism. This program expired May 1, 2003, and the mutual insurer did not renew this program. If a terrorist act occurs at any of our facilities, it could have a significant adverse impact on our financial results.

California Power Agreements

Our merchant energy business has $259.0 million invested in operating power projects of which our ownership percentage represents 140 megawatts of electricity that are sold to Pacific Gas & Electric (PGE) and to Southern California Edison (SCE) in California under power purchase agreements.

As a result of ongoing litigation before the FERC regarding sales into the spot markets of the California Independent System Operator and Power Exchange, we currently estimate that we may be required to pay refunds of between $2 and $6 million for transactions that we entered into with these entities for the period between October 2000 and June 2001. However, we cannot determine the actual amount we could pay because litigation is ongoing and new events could occur that may cause the actual amount, if any, to be materially different from our estimate.

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 2002 Annual Report on Form 10-K.

Interest Rates

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances. These swaps are designated as cash-flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* with 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" during the periods in which the interest payments being hedged occur.

At March 31, 2003, we have net unrealized pre-tax gains of $32.2 million related to hedges, net of associated deferred income tax effects, in "Accumulated other comprehensive income." We expect to reclassify $3.7 million of pre-tax net gains on these swap contracts from "Accumulated other comprehensive income" into "Interest expense" during the next twelve months.

Commodity Prices

At March 31, 2003, our merchant energy business had designated certain fixed-price forward purchase and sale contracts as cash-flow hedges of forecasted transactions for the years 2003 through 2010 under SFAS No. 133.

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

At March 31, 2003, our merchant energy business recorded net unrealized pre-tax losses of $61.0 million on these hedges, net of associated deferred income tax effects, in "Accumulated other comprehensive income." We expect to reclassify $63.2 million of net pre-tax gains on cash-flow hedges from "Accumulated other comprehensive income" into earnings during the next twelve months based on the market prices at March 31, 2003. However, the actual amount reclassified into earnings could vary from the amounts recorded at March 31, 2003 due to future changes in market prices. We recognized into earnings a pre-tax loss of $0.2 million for the quarter ended March 31, 2003 related to the ineffective portion of our hedges.

Accounting Standards Issued

SFAS No. 149

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. The statement amends and clarifies SFAS No. 133 for certain interpretive guidance issued by the Derivatives Implementation Group. SFAS No. 149 is effective after June 30, 2003, for contracts entered into or modified and for hedges designated after the effective date. Currently, we are evaluating this statement and have not determined its impact on our financial results.

FIN 46

In January 2003, the FASB issued Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*, that addresses conditions when an entity should be consolidated based upon variable interests rather than voting interests. Variable interests are ownership interests or contractual relationships that enable the holder to share in the financial risks and rewards resulting from the activities of a Variable Interest Entity (VIE). A VIE can be a corporation, partnership, trust, or any other legal structure used for business purposes. An entity is considered a VIE under FIN 46 if it does not have an equity investment sufficient for it to finance its activities without assistance from variable interests or if its equity investors do not have voting rights.

In order to apply FIN 46, we must evaluate every entity with which we are involved through variable interests to determine whether the entity is a VIE and, if it is, whether or not we are the primary beneficiary of the entity. The primary beneficiary of a VIE is the entity that receives the majority of the entity's expected losses, residual returns, or both. FIN 46 requires us to disclose information about significant variable interests we hold and to consolidate any VIE for which we are the primary beneficiary. As a result, FIN 46 could result in consolidation of an entity that we are associated with other than by (and even in the absence of) a voting ownership interest.

The requirements of FIN 46 apply immediately to all VIEs created after January 31, 2003 and are effective beginning in the third quarter of 2003 for all VIEs created before February 1, 2003. At the time of initially applying FIN 46 to previously unconsolidated VIEs, we will remove from our Consolidated Balance Sheets any previously recognized amounts related to those entities and record the carrying value of the assets, liabilities, and minority interest as reflected in their financial statements. The difference between the net amount added to the Consolidated Balance Sheets and the amounts removed (if any) upon initial adoption of FIN 46, must be recorded in earnings as a cumulative effect of change in accounting principle.

Based upon our initial review of entities with which we are involved through variable interests, we believe that some of these entities are VIEs for which we will have to make disclosures or which we will be required to consolidate when we apply FIN 46 in the third quarter of 2003. The VIEs for which we are the primary beneficiary (and therefore will have to consolidate) include the High Desert Power Project, a geothermal power project, the Safe Harbor Water Power Corporation, and an office building in Annapolis, Maryland, that we partially occupy. The other VIEs with which we are involved (but not as primary beneficiary) include certain other power projects and fuel processing facilities.

Our variable interests in these entities generally consist of equity investments and, in some instances, guarantees of the entities' debt or the value of the entities' assets. The following is summary information about these entities as of March 31, 2003:

	Primary Beneficiary	Significant Interest	Total
	(In millions)		
Total assets	$ 829	$ 470	$ 1,299
Total liabilities	641	414	1,055
Our ownership interest	128	19	147
Other ownership interests	60	37	97
Our maximum exposure to loss	682	69	751

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When we consolidate those VIEs for which we are the primary beneficiary, we will remove from our Consolidated Balance Sheets our previously recorded investment, and we will record in our Consolidated Balance Sheets the total assets, liabilities and other ownership interests as reflected in the financial statements of those entities. We estimate that the net amount we will add to our Consolidated Balance Sheets when we consolidate these VIEs will be less than our recorded investment. As a result, we expect to record a cumulative effect of change in accounting principle of approximately $5 million pre-tax, or $3 million after-tax, charge upon initial adoption of FIN 46 in the third quarter of 2003.

The maximum exposure to loss represents the loss that we would incur if, in the unlikely event, our investment 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, 2003 consists of the following:

- our guarantee of $508.9 million of the High Desert outstanding lease balance and other contractual obligations of $18 million,
- our recorded investment in these VIEs totaling $196 million, and
- guarantees of $28 million of the debt of these VIEs.

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

Accounting Standards Adopted

SFAS No. 143

In 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

In the first quarter of 2003, we adopted this statement and recognized a $112.1 million pre-tax, or $67.7 after-tax, gain as a cumulative effect of change in accounting principle.

Substantially all of this net gain relates to the impact of adopting SFAS No. 143 on the measurement of the liability for the decommissioning of our Calvert Cliffs nuclear power plant. Losses on the adoption of SFAS No. 143 in other areas of our business are offset by a gain relating to the liability for the decommissioning of our Nine Mile Point nuclear power plant. The Calvert Cliffs' gain is primarily due to using a longer discount period as a result of license extension. The previous liability for the decommissioning of Calvert Cliffs was determined in accordance with ratemaking treatment established by the Maryland Public Service Commission (Maryland PSC) and is based on a prior decommissioning cost estimate that contemplated decommissioning being completed at a point in time much closer to the expiration of the plant's original operating license.

As discussed in *Note 1* of our 2002 Annual Report on Form 10-K, we use the composite depreciation method for certain generating facilities and for our utility business. This method currently is an acceptable method of accounting under generally accepted accounting principles and is widely used in the energy, transportation, and telecommunication industries.

Historically, under the composite depreciation method, the anticipated costs of removing assets upon retirement are provided for over the life of those assets as a component of depreciation expense. However, SFAS No. 143 precludes the recognition of expected net future costs of removal as a component of depreciation expense or accumulated depreciation unless they are legal obligations under SFAS No. 143. Instead, we must recognize these costs as incurred, unless the entity is rate regulated under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*.

For our merchant energy business, the elimination of net cost of removal from accumulated depreciation did not have a material impact on our financial results. However, we expect depreciation expense for 2003 and future years to be lower than prior years since depreciation expense will no longer include a component for anticipated cost of removal in excess of salvage. Also, effective January 1, 2003, we only record those asset removal costs that represent legal obligations under SFAS No. 143 prior to their being incurred.

The adoption of SFAS No. 143 did not have a material impact on BGE's financial results. BGE is required by the Maryland PSC to use the composite depreciation method under regulatory accounting. As a result, BGE reclassified $108.4 million of net cost of removal from accumulated depreciation to a regulatory liability in the first quarter of 2003. In accordance with SFAS No. 71, BGE continues to accrue for the future cost of removal for its rate regulated gas and electric utility assets.

The change in our "Asset retirement obligations" liability in the first quarter of 2003 was as follows:

	(In millions)
Liability at January 1, 2003	$ 570.6
Liabilities incurred in current period	
Liabilities settled in current period	
Accretion expense	10.7
Revisions to cash flows	
Liability at March 31, 2003	$ 581.3

(In millions)

The fair value of our nuclear decommissioning trust funds for Calvert Cliffs and Nine Mile Point are reported in "Nuclear decommissioning trust funds" in our Consolidated Balance Sheets. These amounts are legally restricted for funding the costs of nuclear decommissioning.

FIN 45

In November 2002, the FASB issued FIN 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. This Interpretation provides the disclosures to be made by a guarantor in interim and annual financial statements about obligations under certain guarantees. The Interpretation also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation. The adoption of this standard did not have a material impact on our financial results.

EITF 02-3

On October 25, 2002, the EITF reached a consensus on Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, that changed the accounting for certain energy contracts. EITF 02-3 prohibits the use of mark-to-market accounting for any energy-related contracts that are not derivatives. Any non-derivative contracts must be accounted for on the accrual basis and recorded in the income statement gross rather than net upon application of EITF 02-3. This change applied immediately to new contracts executed after October 25, 2002 and applied to existing non-derivative energy-related contracts beginning January 1, 2003.

In the first quarter of 2003, we adopted EITF 02-3 and recognized a $430.0 million pre-tax, or $266.1 million after-tax, charge as a cumulative effect of change in accounting principle.

The primary contracts that were subject to the requirements of EITF 02-3 were our full requirements load-serving contracts and unit-contingent power purchase contracts, which are not derivatives. The majority of these contracts are in Texas and New England and were entered into prior to the shift to accrual accounting earlier in 2002. We discuss our shift to accrual accounting in more detail in our 2002 Annual Report on Form 10-K.

Additionally, we reviewed derivatives we use as supply sources and hedges of contracts that are subject to EITF 02-3. To the extent permitted by SFAS No. 133, we designated derivative contracts used to fulfill our load-serving contracts as either normal purchases or cash flow hedges under SFAS No. 133 effective January 1, 2003.

We summarize the impact on our Consolidated Balance Sheets of applying EITF 02-3 on January 1, 2003 as follows:

	Assets	Liabilities	Net
		(In millions)	
Mark-to-market energy contracts			
Current	$ 144.0	$ 94.1	$ 49.9
Noncurrent	1,348.2	881.5	466.7
Total	1,492.2	975.6	516.6
Other			
Current	85.7	56.8	28.9
Noncurrent	24.2	2.5	21.7
Total	109.9	59.3	50.6
Balance at December 31, 2002	$ 1,602.1	$ 1,034.9	$ 567.2

	Assets	Liabilities	Net
Impact of EITF 02-3 Adoption			
Non-derivative net asset reversed as cumulative effect of change in accounting principle			
Mark-to-market energy contracts	$ (499.2)	$ (119.8)	$ (379.4)
Other	(109.9)	(59.3)	(50.6)
Total non-derivative net asset reversed as cumulative effect of change in accounting principle	(609.1)	(179.1)	(430.0)
Derivatives designated as hedges	(88.3)	(94.4)	6.1
Derivatives designated as normal purchases and sales	(192.6)	(128.3)	(64.3)
Mark-to-market derivatives remaining after adoption of EITF 02-3 on January 1, 2003	$ 712.1	$ 633.1	$ 79.0

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On January 1, 2003, we recorded the $430.0 million non-derivative net asset removed from our Consolidated Balance Sheets as a cumulative effect of change in accounting principle, which reduced our 2003 net income by $266.1 million as previously discussed. The $430.0 million represents $379.4 million of non-derivative contracts recorded as "Mark-to-market energy assets and liabilities" and $50.6 million of "Other assets and liabilities" primarily from the re-designation of Texas contracts to accrual accounting earlier in 2002. The fair value of these contracts will be recognized in earnings as power is delivered.

Additionally, on January 1, 2003, we reclassified the fair value of derivatives designated as hedges as "Risk management assets and liabilities" in the balance sheet and will account for these hedges in accordance with the provisions of SFAS No. 133. At that time, we also reclassified the fair value of derivatives designated as normal purchases and normal sales as "Other assets and liabilities" in the balance sheet and will account for these contracts on the accrual basis, with the fair value amortized into earnings over the lives of the underlying contracts.

Applying EITF 02-3 does not affect our cash flows or our accounting for new load-serving contracts for which we were using accrual accounting since early 2002. Additionally, we continued to mark existing non-derivative energy-related contracts to market for the remainder of 2002.

Related Party Transactions BGE

Income Statement

Under the Restructuring Order issued by the Maryland PSC in November 1999, BGE is providing standard offer service to customers at fixed rates over various time periods during the transition period from July 1, 2000 to June 30, 2006, for those customers that do not choose an alternate supplier. Constellation Power Source is under contract to provide BGE with 100% of the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period, and 90% of the energy and capacity for the final three years (July 1, 2003 through June 30, 2006) of the transition period. The cost of BGE's purchased energy from nonregulated affiliates of Constellation Energy to meet its standard offer service obligation was $243.5 million for the quarter ended March 31, 2003 compared to $241.0 million for the same period in 2002.

In addition, BGE is charged by Constellation Energy for 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. Management believes this method of allocation is reasonable and approximates the cost BGE would have incurred as an unaffiliated entity. These costs were approximately $8.9 million for the quarter ended March 31, 2003 compared to $8.5 million for the same period in 2002.

Balance Sheet

BGE participates in a cash pool under a Master Demand Note agreement with Constellation Energy. Under this arrangement, participating subsidiaries may invest in or borrow from the pool at market interest rates. Constellation Energy administers the pool and invests excess cash in short-term investments or issues commercial paper to manage consolidated cash requirements. BGE had invested $338.7 million at March 31, 2003 and $338.1 million at December 31, 2002 under this arrangement.

Amounts related to corporate functions performed at the Constellation Energy holding company, BGE's purchases to meet its standard offer service obligation, and BGE's charges to Constellation Energy and its nonregulated affiliates for certain services it provides them result in intercompany balances on BGE's Consolidated Balance Sheets.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in the *Notes to Consolidated Financial Statements* on page 11.

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 "utility business" are to BGE.

Our merchant energy business is a competitive provider of energy solutions for large customers in North America. It has electric generation assets located in various regions of the United States and provides energy solutions to meet customers' needs. Our merchant energy business focuses on serving the full energy and capacity requirements (load-serving activities) of, and providing other risk management activities for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and large commercial and industrial customers. These load-serving activities typically occur in regional markets in which end use customer electricity rates have been deregulated and thereby separated from the cost of generation supply.

BGE is a regulated electric and gas public transmission and distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland.

Our other nonregulated businesses:

- design, construct, and operate single-site heating, cooling, and cogeneration facilities for commercial and industrial customers,
- provide home improvements, service heating, air conditioning, plumbing, electrical, and indoor air quality systems, and provide electric and natural gas retail marketing, and
- own and operate a district cooling system for commercial customers in the City of Baltimore, Maryland.

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Latin American distribution project and in a fund that holds interests in two South American energy projects.

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 future capital expenditures.

As you read this discussion and analysis, refer to our Consolidated Statements of Income on page 1, which present the results of our operations for the quarters ended March 31, 2003 and 2002. We analyze and explain the differences between periods in the specific line items of the Consolidated Statements of Income.

Restatement of Revenues and Expenses

During the first quarter of 2003, in preparation for and following the implementation of changes in the market design in New England, our merchant energy business recorded certain transactions with the New England Independent System Operator (ISO) by computing gross sales and gross purchases by delivery location. This means that when our sources of power and ultimate load-serving customers were in different New England delivery locations, we recorded the transactions as a purchase from the third-party power provider in the source location and a sale to the New England ISO in that location. Then in the zone where our ultimate load-serving customer was served, we recorded a purchase from the New England ISO and a sale to the ultimate load-serving customer in that location. This gross reporting was consistent with the market design change in New England and ensured the appropriate capture of congestion and other costs in our systems necessary for risk management and settlement purposes. The New England ISO is however not a principal in these transactions; and as such, for financial reporting purposes we should have recorded these transactions on a net basis for the New England region as a whole and not on a gross basis.

As a result, we have restated the unaudited Consolidated Financial Statements for the quarter ended March 31, 2003, and made corresponding amendments to Management's Discussion and Analysis of Financial Condition and Results of Operations. The restatement has resulted in a reduction to "Nonregulated revenues" and "Operating expenses" of $282.9 million for the quarter ended March 31, 2003. The restatement does not affect income from operations, earnings, cash flows or common shareholders' equity, nor does it affect revenues or

expenses for any period other than the quarter ended March 31, 2003.

The principal effects of the restatement on our merchant energy business are described in the *Results of Operations Merchant Energy Business* section beginning on page 30 of this discussion and analysis and in the *Notes to the Consolidated Financial Statements* on page 9.

Critical Accounting Policies

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements that were prepared in accordance with accounting principles generally accepted in the United States of America. Management makes estimates and assumptions when preparing financial statements. These estimates and assumptions affect various matters, including:

- our reported amounts of assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements,
- our disclosure of contingent assets and liabilities at the dates of the financial statements, and
- our reported amounts of revenues and expenses in our Consolidated Statements of Income during the reporting periods.

These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual amounts could materially differ from these estimates.

The Securities and Exchange Commission (SEC) issued disclosure guidance for accounting policies that management believes are most "critical." The SEC defines these critical accounting policies as those that are both most important to the portrayal of a company's financial condition and results and require management's most difficult, subjective, or complex judgment, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods.

Management believes the following accounting policies represent critical accounting policies as defined by the SEC. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1* of our 2002 Annual Report on Form 10-K.

Revenue Recognition Mark-to-Market Method of Accounting

Our merchant energy business engages in origination and risk management activities using contracts for energy, other energy-related commodities, and related derivative contracts. We record merchant energy business revenues using two methods of accounting: accrual accounting and mark-to-market accounting. We describe our use of accrual accounting in more detail in *Note 1* of our 2002 Annual Report on Form 10-K.

On October 25, 2002, the Emerging Issues Task Force (EITF) reached a consensus on Issue 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under EITF Issues No. 98-10 and No. 00-17*. This consensus affects the accounting for certain contracts and the application of the mark-to-market method of accounting. We describe our current application of the mark-to-market method of accounting based on the impact of the consensus on EITF 02-3 below. The main provisions of EITF 02-3 are as follows:

- The EITF rescinded Issue 98-10. As a result, this consensus prohibits mark-to-market accounting for energy-related contracts that do not meet the definition of a derivative under SFAS No. 133. Any contracts subject to the consensus must be accounted for on the accrual basis.
- The EITF indicates that an entity should not record unrealized gains or losses at the inception of derivative contracts unless the fair value of each contract in its entirety is evidenced by quoted market prices or other current market transactions for contracts with similar terms and counterparties.
- The EITF requires gains and losses on derivative energy trading contracts (whether realized or unrealized) to be reported as revenue on a net basis in the income statement.

We use mark-to-market accounting for energy trading activities and for derivatives and other contracts for which we are not permitted to use accrual accounting or hedge accounting. These mark-to-market activities include derivative contracts for energy and other energy-related commodities. Under the mark-to-market method of accounting, we record the fair value of energy contracts as mark-to-market energy assets and liabilities at the time of contract execution. We record the changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income.

Mark-to-market energy assets and liabilities consist of a combination of energy and energy-related derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors. 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.

We record reserves to reflect uncertainties associated with certain estimates inherent in the determination of fair value that are not incorporated in market price information or other market-based estimates used to determine fair value of our mark-to-market energy contracts. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the risks for which we record reserves and determining the level of such reserves and changes in those levels.

We describe below the main types of reserves we record and the process for establishing each. Generally, increases in reserves reduce our earnings, and decreases in reserves increase our earnings. However, all or a portion of the effect on earnings of changes in reserves may be offset by changes in the value of the underlying positions.

- Close-out reserve this reserve represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This reserve has the effect of valuing "long" positions at the bid price and "short" positions at the offer price. We compute this reserve using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our open positions for each year. To the extent that we are not able to obtain market information for similar contracts, the close-out reserve is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. The level of total close-out reserves increases as we have larger unhedged positions, bid-offer spreads increase, or market information is not available, and it decreases as we reduce our unhedged positions, bid-offer spreads decrease, or market information becomes available.

- Credit-spread adjustment for risk management purposes, we compute the value of our mark-to-market assets and liabilities using a risk-free discount rate. In order to compute fair value for financial reporting purposes, we adjust the value of our mark-to-market assets to reflect the credit-worthiness of each individual counterparty based upon published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this reserve by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this reserve increases as our credit exposure to counterparties increases, the maturity terms of our transactions increase, or the credit ratings of our counterparties deteriorate, and it decreases when our credit exposure to counterparties decreases, the maturity terms of our transactions decrease, or the credit ratings of our counterparties improve.

Market prices for energy and energy-related commodities vary based upon a number of factors. Changes in market prices will affect both the recorded fair value of our mark-to-market energy contracts and the level of future revenues and costs associated with accrual-basis activities. Changes in the value of our mark-to-market energy contracts will affect our earnings in the period of the change, while changes in forward market prices related to accrual-basis revenues and costs will affect our earnings in future periods to the extent those prices are realized. We cannot predict whether, or to what extent, the factors affecting market prices may change, but those changes could be material and could affect us either favorably or unfavorably. We discuss our market risk in more detail in the *Market Risk* section of our 2002 Annual Report on Form 10-K.

EITF 02-3 affects the timing of recognizing earnings on new non-derivative transactions. In general, earnings on new transactions subject to EITF 02-3 are no longer recognized at the inception of the transactions as they were under mark-to-market accounting because they are subject to accrual accounting and are recognized over the term of the transaction. As a result, while total earnings over the term of a transaction will be unchanged, we expect that our reported earnings for contracts subject to EITF 02-3 will generally match the cash flows from those contracts more closely. In addition, our reported earnings may be less volatile under accrual accounting than under mark-to-market accounting, which reflects changes in fair value of contracts when they occur rather than when products are delivered and costs are incurred.

Alternatively, other comprehensive income may have greater fluctuations because of a larger number of derivative contracts that we designated for hedge accounting under SFAS No. 133, but these fluctuations will not affect current period earnings or cash flows. Additionally, because we record revenues and costs on a gross basis under accrual accounting, our revenues and costs could increase, but our earnings will not be affected by gross versus net reporting.

The impact of EITF 02-3 will be affected by many factors, including:

- our ability to designate and qualify derivative contracts for normal purchase and sale accounting or hedge accounting under SFAS No. 133, potential volatility in earnings from derivative contracts that serve as economic hedges but do not meet the accounting requirements to qualify for normal purchase and sale accounting or hedge accounting,

our ability to enter into new mark-to-market derivative origination transactions, and

sufficient liquidity and transparency in the energy markets to permit us to record gains at inception of new derivative contracts because fair value is evidenced by quoted market prices or current market transactions.

We discuss the impact of mark-to-market accounting on our financial results in the *Results of Operations Merchant Energy Business* section on page 30.

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value

We are required to evaluate certain assets that have long lives (for example, generating property and equipment and real estate) to determine if they are impaired when certain conditions exist. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* provides the accounting for impairments of long-lived assets. We are required to test our long-lived assets for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes would be as follows:

a significant decrease in the market price of a long-lived asset,

a significant adverse change in the manner an asset is being used or its physical condition,

an adverse action by a regulator or in the business climate,

an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,

a current-period loss combined with a history of losses or the projection of future losses, or

a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

For long-lived assets that are expected to be held and used, SFAS No. 144 requires that an impairment loss shall only be recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable under SFAS No. 144 if the carrying amount exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. Therefore, when we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets. This necessarily involves judgment surrounding the inherent uncertainty of future cash flows.

In order to estimate an asset's future cash flows, we will consider historical cash flows, as well as reflect our understanding of the extent to which future cash flows will be either similar to or different from past experience based on all available evidence. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). If we are considering alternative courses of action to recover the carrying amount of a long-lived asset (such as the potential sale of an asset), we probability-weight the alternative courses of action to establish the cash flows.

We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, and operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

For long-lived assets that can be classified as assets to be disposed of by sale under SFAS No. 144, an impairment loss shall be recognized to the extent their carrying amount exceeds their fair value, including costs to sell.

The estimation of fair value under SFAS No. 144, whether in conjunction with an asset to be held and used or with an asset to be disposed of by sale, also involves estimation and judgment. We consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may consider prices of similar assets, consult with brokers, or employ other valuation techniques. Often, we will discount the estimated future cash flows associated with the asset using a single interest rate that is commensurate with the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. The use of these methods involves the same inherent uncertainty of future cash flows as discussed above with respect to undiscounted cash flows and actual future market prices and project costs could vary from those used in our estimates, and the impact of such variations could be material.

We are also required to evaluate our equity-method and cost-method investments (for example, in partnerships that own power projects) to determine whether or not they are impaired. Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock,* provides the accounting for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value

that is considered an "other than a temporary" decline in value.

The evaluation and measurement of impairments under the APB No. 18 standard involves the same uncertainties as described above for long-lived assets that we own directly and account for in accordance with SFAS No. 144. Similarly, the estimates that we make with respect to our equity and cost-method investments are subject to variation, and the impact of such variations could be material. Additionally, if the projects in which we hold these investments recognize an impairment under the provisions of SFAS No. 144, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value under APB No. 18.

Asset Retirement Obligations

We incur legal obligations associated with the retirement of certain long-lived assets. SFAS No. 143, *Accounting for Asset Retirement Obligations,* provides the accounting for legal obligations associated with the retirement of long-lived assets. We incur such legal obligations as a result of environmental and other government regulations, contractual agreements, and other factors. The application of this standard requires significant judgment due to the large number and diverse nature of the assets in our various businesses and the estimation of future cash flows required to measure legal obligations associated with the retirement of specific assets.

SFAS No. 143 requires the use of an expected present value methodology in measuring asset retirement obligations that involves judgment surrounding the inherent uncertainty of the probability, amount and timing of payments to settle these obligations, and the appropriate interest rates to discount future cash flows. We use our best estimates in identifying and measuring our asset retirement obligations in accordance with SFAS No. 143.

Specifically, our nuclear decommissioning costs represent our largest asset retirement obligation. This obligation primarily results from the requirement to decommission and decontaminate the Calvert Cliffs and Nine Mile Point plants in connection with their future retirement. We revised our site-specific decommissioning cost estimates as part of the process to determine our nuclear asset retirement obligations. However, given the magnitude of the amounts involved, complicated and ever-changing technical/regulatory requirements, and the very long time horizons involved, the actual obligation could vary from the assumptions used in our estimates, and the impact of such variations could be material.

Events of 2003

Workforce Reduction Costs

During the first quarter of 2003, we incurred costs related to workforce reduction efforts initiated in previous years. We recorded $0.7 million pre-tax expense, of which BGE recorded $0.3 million, associated with deferred payments to employees eligible for the 2001 Voluntary Special Early Retirement Programs.

Sale of Non-Core Assets

During the first quarter of 2003, our other nonregulated businesses recognized $13.7 million of pre-tax gains on the sales of non-core assets as follows:

- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy, a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001, and

a $1.2 million pre-tax installment sale gain on a parcel of real estate.

Generating Facility Commenced Operations

In April 2003, our High Desert Power Project in Victorville, CA, an 830 megawatt (MW) gas-fired combined cycle facility, commenced operations. The project has a long-term power sales agreement with the California Department of Water Resources (CDWR). The contract is a "tolling" structure, under which the CDWR pays a fixed amount of $12.1 million per month and provides CDWR the right, but not the obligation, to purchase power from the project at a price linked to the variable cost of production. During the term of the contract, which runs for seven years and nine months from the April 2003 commencement date of the plant, the project will provide energy exclusively to the CDWR.

The High Desert Power Project uses an off-balance sheet financing structure through a special-purpose entity (SPE) that currently qualifies as an operating lease.

We discuss our High Desert project and associated accounting in more detail in the *Capital Resources* section on page 43.

Calvert Cliffs Extended Outage

In April 2003, our merchant energy business completed the Unit 2 steam generators replacement and refueling outage at Calvert Cliffs. This outage was completed in 66 days, 58 fewer days than a similar outage completed at Calvert Cliff's Unit 1 in June 2002.

Portfolio Acquisitions

During 2003, we acquired the following:

customer load-serving contracts representing 940 MW and corresponding supply portfolio from a subsidiary of CMS Energy Corp., for $34 million,

certain competitive energy supply contracts with commercial and industrial customers, including 300 MW of electricity and certain natural gas customers, from Nicor Energy L.L.C. in Michigan, Illinois, and Indiana, and

a portfolio of competitive energy supply contracts with commercial and industrial customers, representing 125 MW, from Dynegy Inc., in Alberta, Canada.

Dividend Increase

In January 2003, we announced an increase in our quarterly dividend to 26 cents per share on our common stock payable April 1, 2003 to holders of record on March 10, 2003. This is equivalent to an annual rate of $1.04 per share. Previously, our quarterly dividend on our common stock was 24 cents per share, equivalent to an annual rate of 96 cents per share.

Strategy

We are pursuing a balanced strategy to generate power through our national fleet of plants and to distribute power through our regulated Maryland utility, BGE, and through our national competitive supply activities. Our generation fleet is strategically located in deregulated markets across the country and is diversified by fuel type, including nuclear, coal, gas, and renewable sources. We intend to remain diversified between owned generation, contractual generation, and regulated distribution and competitive supply.

We expect this focus to provide growth opportunities along with more stable and predictable earnings, cash flows and dividends. The strategy for our merchant energy business is to be a leading competitive supplier of energy solutions for large customers in North America.

The integration of electric generation assets with origination and risk management of energy and energy-related commodities allows our merchant energy business to manage energy price risk over geographic regions and over time. Our focus is on providing solutions to customers' energy needs, and our origination and risk management operation adds value to our generation assets by providing national market access, market infrastructure, real-time market intelligence, risk management and arbitrage opportunities, and transmission and transportation expertise. Generation capacity supports our origination and risk management operation by providing a source of reliable power supply that provides a physical hedge for some of our load-serving activities.

To achieve our strategic objectives, we expect to continue to pursue opportunities that expand our access to customers and to support our origination and risk management operation with generation assets that have diversified geographic, fuel, and dispatch characteristics. We also expect to use a disciplined growth strategy through originating transactions with large customers and by acquiring and developing additional generating facilities when desirable to support our merchant energy business.

Our merchant energy business will focus on long-term, high-value sales of energy, capacity, commodities, and related products to large customers, including distribution utilities, industrial customers, and large commercial customers primarily in the regional markets in which end-use customer electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include the New England region, the New York region, the Mid-Atlantic region, the Mid-Continent region, Texas, California, and certain areas in Canada.

The growth of BGE and our other retail energy services businesses is expected through focused and disciplined expansion primarily from new customers.

Customer choice, regulatory change, and energy market conditions significantly impact our business. In response, we regularly evaluate our strategies with these goals in mind: to improve our competitive position, to anticipate and adapt to business environment and regulatory changes, and to maintain a strong balance sheet and investment-grade credit quality.

We also might consider one or more of the following strategies:

- the complete or partial separation of BGE's transmission function from its distribution function,
- mergers or acquisitions of utility or non-utility businesses or assets, and

- sale of assets or one or more businesses.

Business Environment

With the shift toward customer choice, competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss these various factors in the *Forward Looking Statements* section in Item 5. Other Information of our March 31, 2003 Quarterly Report on Form 10-Q.

In this section, we discuss in more detail several issues that affect our businesses.

General Industry

Over the past several years, the utility industry and energy markets experienced significant changes as a result of less liquid and more volatile wholesale markets, credit quality deterioration of various industry participants, and the slowing of the U.S. economy.

The energy markets also were affected by other significant events, including expanded investigations by state and federal authorities into business practices of energy companies in the deregulated power and gas markets relating to "wash trading" to inflate revenues and volumes, and other trading practices designed to manipulate market prices. In addition, several merchant energy businesses significantly reduced their energy trading activities due to deteriorating credit quality.

During the first quarter of 2003, the energy markets continued to be highly volatile with significant increases in natural gas and power prices as well as the continuation of reduced liquidity in the marketplace. During the first quarter of 2003, Constellation Power Source's average value at risk was $4.0 million using a 95% confidence level. We discuss the value-at-risk calculation in more detail in the *Market Risk* section of our 2002 Annual Report on Form 10-K.

We continue to actively manage our credit portfolio to attempt to reduce the impact of a potential counterparty default. As of March 31, 2003, approximately 89% of our credit portfolio was rated at least investment grade by the major rating agencies, with 3% rated below investment grade and 8% not rated. Of the 8% not rated, 81% primarily represents governmental entities, municipalities, cooperatives, or other load-serving entities that we assess are equivalent to investment grade based on internal credit ratings.

We continue to examine plans to achieve our strategies and to further strengthen our balance sheet and enhance our liquidity. We discuss our strategies in the *Strategy* section on page 25. We discuss our liquidity in the *Financial Condition* section on page 42.

Electric Competition

We are facing competition in the sale of electricity in wholesale power markets and to retail customers.

Maryland

As a result of the deregulation of electric generation in Maryland, the following occurred effective July 1, 2000:

- All customers can choose their electric energy supplier. BGE provides fixed price standard offer service over various time periods for different classes of customers that do not select an alternative supplier until June 30, 2006.
- While BGE does not sell electric commodity to all customers in its service territory, BGE does deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.
- BGE provides a market rate standard offer service for those commercial and industrial customers who are no longer eligible for fixed price standard offer service until June 30, 2006.
- BGE residential base rates will not change before July 2006. While total residential base rates remain unchanged over the transition period (July 1, 2000 through June 30, 2006), annual standard offer service rate increases are offset by corresponding decreases in the competitive transition charge (CTC) that BGE receives from its customers.
- Commercial and industrial customers have several service options that will fix electric energy rates through June 30, 2004 and transition charges through June 30, 2006.
- BGE transferred, at book value, its generating assets and related liabilities to the merchant energy business.

Our origination and risk management operation provides BGE with 100% of the energy and capacity required to meet its standard offer service obligations through June 30, 2003. Our origination and risk management operation obtains the energy and capacity to supply BGE's standard offer service obligations from our merchant energy generating plants in the PJM Interconnection (PJM) region, supplemented with energy and capacity purchased from the wholesale market, as necessary.

In August 2001, BGE entered into contracts with our origination and risk management operation to supply 90% and Allegheny Energy Supply Company, LLC (Allegheny) to supply the remaining 10% of BGE's standard offer service for the final three years (July 1, 2003 to June 30, 2006) of the transition period. Currently, the credit ratings of Allegheny are below

investment grade. Under the terms of the contract, in certain circumstances, BGE has the right to request additional credit support from Allegheny to secure performance under the contract. BGE has exercised certain rights under the contract and is working closely with Allegheny with respect to the contract.

On November 15, 2002, BGE entered into a proposed settlement agreement with parties representing customers, industry, utilities, suppliers, the Maryland Energy Administration, the Maryland PSC's Staff, and the Office of People's Counsel which, among other things, extends BGE's obligation to supply standard offer service. Under the proposed settlement agreement, BGE would be obligated to provide market-based standard offer service to residential customers until June 30, 2010, and for commercial and industrial customers for a one, two or four year period beyond June 30, 2004, depending on customer size. The rates charged during this time would recover BGE's wholesale power supply costs and would include an administrative fee. On April 29, 2003, the Maryland PSC approved the proposed settlement agreement.

Other States

Several states, other than Maryland, have supported deregulation of the electric industry. The pace of deregulation in other states varies based on historical moves to competition and responses to recent market events. Certain states that were considering deregulation have slowed their plans or postponed consideration. In addition, other states are reconsidering deregulation.

In response to regional market differences and to promote competitive markets, the FERC proposed initiatives promoting the formation of Regional Transmission Organizations and a standard market design. If approved, these market changes could provide additional opportunities for our merchant energy business. We discuss these initiatives in the *FERC Regulation Regional Transmission Organizations and Standard Market Design* section on page 28.

As a result of ongoing litigation before the FERC regarding sales into the spot markets of the California Independent System Operator and Power Exchange, we currently estimate that we may be required to pay refunds of between \$2 and \$6 million for transactions that we entered into with these entities for the period between October 2000 and June 2001. However, we cannot determine the actual amount we could pay because litigation is ongoing and new events could occur that could cause the actual amount, if any, to be materially different from our estimate.

Gas Competition

Currently, no regulation exists for the wholesale price of natural gas as a commodity, and the regulation of interstate transmission at the federal level has been reduced. All BGE gas customers have the option to purchase gas from other suppliers.

Regulation by the Maryland PSC

In addition to electric restructuring which was discussed earlier, regulation by the Maryland PSC influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers for the electric distribution and gas businesses. The Maryland PSC incorporates into BGE's electric rates the transmission rates determined by FERC. BGE's electric rates are unbundled to show separate components for delivery service, competitive transition charges, standard offer services (generation), transmission, universal service, and certain taxes. The rates for BGE's regulated gas business continue to consist of a "base rate" and a "fuel rate."

Base Rate

The base rate is the rate the Maryland PSC allows BGE to charge its customers for the cost of providing them service, plus a profit. BGE has both an electric base rate and a gas base rate. Higher electric base rates apply during the summer when the demand for electricity is higher. Gas base rates are not affected by seasonal changes.

BGE may ask the Maryland PSC to increase base rates from time to time. The Maryland PSC historically has allowed BGE to increase base rates to recover increased utility plant asset costs and higher operating costs, plus a profit, beginning at the time of replacement. Generally, rate increases improve our utility earnings because they allow us to collect more revenue. However, rate increases are normally granted based on historical data, and those increases may not always keep pace with increasing costs. Other parties may petition the Maryland PSC to decrease base rates.

As a result of the deregulation of electric generation in Maryland, BGE's residential electric base rates are frozen until 2006. Electric delivery service rates are frozen until 2004 for commercial and industrial customers. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers.

Gas Fuel Rate

We charge our gas customers separately for the natural gas they purchase from us. The price we charge for the natural gas is based on a market-based rates incentive mechanism approved by the Maryland PSC. We discuss market-based rates and a current proceeding with the Maryland PSC in more detail in the *Gas Cost Adjustments* section on page 41 and in *Note 1* of our 2002 Annual Report on Form 10-K.

FERC Regulation

Regional Transmission Organizations and Standard Market Design

In December 1999, FERC issued Order 2000, amending its regulations under the Federal Power Act to advance the formation of Regional Transmission Organizations (RTOs) that would allow easier access to transmission.

On July 31, 2002, the FERC issued a proposed rulemaking regarding implementation of a standard market design (SMD) for wholesale electric markets. The SMD rulemaking is intended to complement FERC's RTO order, and will require RTOs to substantially comply with its provisions. The SMD proposals require transmission providers to turn over the operation of their facilities to an independent operator that will operate them consistent with a revised market structure proposed by the FERC. According to the FERC, the revised market structure will reduce inefficiencies caused by inconsistent market rules and barriers to transmission access. The FERC proposed that its rule be implemented in stages by October 1, 2004. Comments on the SMD proposal were submitted in February 2003.

In April 2003, the FERC issued a report that indicated its position with respect to the proposed rulemaking and announced that it intends to leave relatively unmodified existing RTO practices, to allow flexibility among regional approaches, to allow phased-in implementation of the final rule, and to provide an increased deference to states' concerns. Concurrently, proposed federal legislation has been introduced that would remand to FERC the entire rulemaking process, require the issuance of a new proposed rule, and delay implementation of any final rule for a number of years.

We believe that, while the original SMD proposal would have led to uniform rules that would have been largely favorable to Constellation Energy and BGE, the revised regional approach should result in improved market operations across various regions. Overall, the trend continues to be toward increased competition in the regions. The region where BGE operates is expected to be relatively unaffected by this proceeding.

In 1997, BGE turned over the operation of its transmission facilities to PJM, a FERC approved RTO, which generally conducts its operations in accordance with FERC standard market design principles.

Weather

Merchant Energy Business

Weather conditions in the different regions of North America influence the financial results of our merchant energy business. Weather conditions can affect the supply of and demand for electricity and fuels, and changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. Similarly, the demand for and price of natural gas and oil are higher in the winter. However, all regions of North America typically do not experience extreme weather conditions at the same time.

BGE

Weather affects the demand for electricity and gas for our regulated businesses. Very hot summers and very cold winters increase demand. Mild weather reduces demand. Residential sales for our regulated businesses are impacted more by weather than commercial and industrial sales, which are mostly affected by business needs for electricity and gas.

However, the Maryland PSC allows us to record a monthly adjustment to our regulated gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the *Weather Normalization* section on page 40.

We measure the weather's effect using "degree-days." The measure of degree-days for a given day is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Cooling degree-days result when the average daily actual temperature exceeds the 65 degree baseline. Heating degree-days result when the average daily actual temperature is less than the baseline.

During the cooling season, hotter weather is measured by more cooling degree-days and results in greater demand for electricity to operate cooling systems. During the heating season, colder weather is measured by more heating degree-days and results in greater demand for electricity and gas to operate heating systems.

We show the number of heating degree-days in the quarters ended March 31, 2003 and 2002, and the percentage change in the number of degree-days between these periods in the following table:

Quarter Ended March 31,	**2003**	**2002**
Heating degree-days	**2,759**	2,123
Percent change from prior period	30.0%	

Other Factors

A number of other factors significantly influence the level and volatility of prices for energy commodities and related derivative products for our merchant energy business. These factors include:

- seasonal daily and hourly changes in demand,
- number of market participants,
- extreme peak demands,
- available supply resources,
- transportation availability and reliability within and between regions,
- implementation of new market rules governing the operations of regional power pools,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions, and
- changes in the nature and extent of federal and state regulations.

These other factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the country as a result of regional differences in:

- weather conditions,
- market liquidity,
- capability and reliability of the physical electricity and gas systems, and
- the nature and extent of electricity deregulation.

Other factors, aside from weather, also impact the demand for electricity and gas in our regulated businesses. These factors include the "number of customers" and "usage per customer" during a given period. We use these terms later in our discussions of regulated electric and gas operations. In those sections, we discuss how these and other factors affected electric and gas sales during the periods presented.

The number of customers in a given period is affected by new home and apartment construction and by the number of businesses in our service territory.

Usage per customer refers to all other items impacting customer sales that cannot be measured separately. These factors include the strength of the economy in our service territory. When the economy is healthy and expanding, customers tend to consume more electricity and gas. Conversely, during an economic downtrend, our customers tend to consume less electricity and gas.

Accounting Standards Adopted and Issued

We discuss recently adopted and issued accounting standards in the *Notes to Consolidated Financial Statements* beginning on page 16.

Results of Operations for the Quarter Ended March 31, 2003 Compared with the Same Period of 2002

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 42.

Overview

Results

Quarter Ended March 31,	2003	2002
	(In millions, after-tax)	
Merchant energy	**$ (20.5)**	$ 27.0
Regulated electric	**50.2**	16.4
Regulated gas	**28.6**	27.8
Other nonregulated	**8.7**	157.4
Income Before Cumulative Effects of Changes in Accounting Principles	**67.0**	228.6
Cumulative Effects of Changes in Accounting Principles (see Notes)	**(198.4)**	
Net (Loss) Income	**$ (131.4)**	$ 228.6
Special Items Included in Operations		
Gains on sale of investments and other assets	**$ 8.3**	$ 164.2
Workforce reduction costs	**(0.4)**	(15.6)
Total Special Items	**$ 7.9**	$ 148.6

Quarter Ended March 31, 2003

Our total net income for the quarter ended March 31, 2003 decreased $360.0 million, or $2.20 per share, compared to the same period of 2002 mostly because of the following:

- We recorded a $266.1 million after-tax, or $1.61 per share, loss for the cumulative effect of adopting EITF 02-3. This was partially offset by a $67.7 million after-tax, or $.41 per share, gain for the cumulative effect of adopting SFAS No. 143. We discuss these cumulative effect items in more detail in the *Notes to Consolidated Financial Statements* on page 17.
- We recognized a $163.3 million after-tax, or $1.00 per share, gain on the sale of our investment in Orion in 2002 that had a positive impact in that period.

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- We had lower earnings from our competitive supply activities mostly due to lower mark-to-market results, the unfavorable impact of volatile gas and power prices, cold northeastern weather, and outages at third party plants.
- We had higher fixed charges due to the issuance of $2.5 billion of long-term debt in 2002 that was primarily used to repay short-term borrowings, and due to lower capitalized interest because of the new generating facilities that commenced

operations since mid-2002.

Our merchant energy business had lower earnings from our investments in qualifying facilities and domestic power projects.

These decreases were partially offset by the following:

We had higher earnings from our regulated electric business mostly because of colder winter weather in the central Maryland region and favorable operating expense performance.

We had higher earnings from the addition of NewEnergy and Alliance, which were acquired in late 2002, and from wholesale accrual origination activities.

We had higher workforce reduction costs in 2002 that had a negative impact in that period.

Our other nonregulated businesses recognized a gain of $8.3 million after-tax, or $.05 per share, related to non-core asset sales.

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 large customers in North America. As discussed in the *Business Environment Electric Competition* section on page 26, in connection with the July 1, 2000 implementation of customer choice in Maryland, BGE's generating assets became part of our nonregulated merchant energy business, and our origination and risk management operation began selling to BGE the energy and capacity required to meet its standard offer service obligations for the first three years (July 1, 2000 to June 30, 2003) of the transition period.

In August 2001, BGE entered into a contract with our origination and risk management operation to provide 90% of the energy and capacity required for BGE to meet its standard offer service requirements for the final three years (July 1, 2003 to June 30, 2006) of the transition period. Our merchant energy business revenues also include 90% of the competitive transition charges (CTC revenues) BGE collects from its customers and the portion of BGE's revenues providing for nuclear decommissioning costs.

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 on page 21 and in *Note 1* of our 2002 Annual Report on Form 10-K. We summarize our policies as follows:

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

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

We record changes in the fair value of contracts that are subject to mark-to-market accounting in revenues on a net basis in the period in which the change occurs.

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of our contracts and in recording revenues from those contracts. We discuss the effects of mark-to-market accounting on our revenues in the *Competitive Supply Mark-to-Market Revenues* section on page 33.

In the first quarter of 2003, we adopted EITF 02-3 that required certain contracts to be accounted for on the accrual basis and recorded gross rather than net upon application of EITF 02-3. We determined that the primary contracts affected were our full requirements load-serving contracts and unit-contingent power purchase contracts. The majority of these contracts were in Texas and New England and were entered into prior to the shift to accrual accounting earlier in 2002, as discussed in our 2002 Annual Report on Form 10-K. We discuss the adoption of EITF 02-3 in more detail in the *Notes to Consolidated Financial Statements* on page 18.

After the re-designation of existing contracts to non-trading, we record revenues and expenses on a gross basis, but this does not have a material impact on earnings because the resulting increase in revenues is accompanied

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by a similar increase in fuel and purchased energy expenses.

EITF 02-3 affects the timing of recognizing earnings on new non-derivative transactions. In general, earnings on new transactions subject to EITF 02-3 no longer are recognized at the inception of the transactions as they were under mark-to-market accounting because they are subject to accrual accounting and are recognized over the term of the transaction.

Additionally, we also expect lower earnings volatility for this portion of our business because unrealized changes in the fair value of load-serving contracts will no longer be recorded as revenue at the time of the change as they were under mark-to-market accounting.

Our merchant energy business results were as follows:

Results

Quarter Ended March 31,

	2003	2002
	(Restated)	
	(In millions)	
Revenues	**$ 1,677.1**	$ 490.0
Fuel and purchased energy expenses	**(1,379.1)**	(152.0)
Operations and maintenance expenses	**(220.1)**	(206.3)
Workforce reduction costs	**(0.4)**	(5.0)
Depreciation and amortization	**(50.9)**	(56.7)
Accretion of asset retirement obligations	**(10.7)**	
Taxes other than income taxes	**(25.9)**	(20.6)
(Loss) Income from Operations	**$ (10.0)**	$ 49.4
(Loss) Income Before Cumulative Effects of Changes in Accounting Principles (after-tax)	**$ (20.5)**	$ 27.0
Cumulative Effects of Changes in Accounting Principles (after-tax)	**(198.4)**	
Net (Loss) Income	**$ (218.9)**	$ 27.0
Special Items Included in Operations (after-tax)		
Workforce reduction costs	**$ (0.2)**	$ (3.0)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 12 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues and Fuel and Purchased Energy Expenses

Our origination and risk management operation manages our costs of procuring fuel and energy and revenues we realize from the sale of energy to our customers. The difference between revenues and fuel and purchased energy expenses is the primary driver of 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 the relationship between revenues and fuel and purchased energy expenses. We discuss non-fuel direct costs, such as ancillary services, transmission costs, financing, and legal costs in conjunction with other operations and maintenance expenses later in this section.

We analyze our merchant energy revenues and fuel and purchased energy expenses in the following categories because of differences in the revenue sources, the nature of fuel and purchased energy expenses, and the risk profile of each category.

PJM Platform our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM region for which the output is primarily used to serve BGE.

Plants with Power Purchase Agreements our generating facilities with long-term power purchase agreements, including our Nine Mile Point, Oleander, and University Park generating facilities. In addition, we will include the results of our High Desert Power Project beginning in the second quarter of 2003.

Competitive Supply our wholesale business that provides load-serving activities to distribution utilities (primarily in Texas and New England), other wholesale origination and risk management services, and electric and gas retail energy services to large commercial and industrial customers.

Other our other gas-fired generating facilities, investments in qualifying facilities and domestic power projects, and our generation and consulting services. With the acquisition of the load-serving customers from CMS Energy Corp., as previously discussed on page 25, the results of other gas-fired facilities in the mid-continent region will become part of our competitive supply activities beginning in the second quarter of 2003.

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

Quarter Ended March 31,

	2003		2002	
	(Restated)			
	(Dollar amounts in millions)			
Revenues:				
PJM Platform	**$ 375.7**		$ 286.4	
Plants with Power Purchase Agreements	**109.2**		92.5	
Competitive Supply	**1,159.3**		87.0	
Other	**32.9**		24.1	
Total	**$ 1,677.1**		$ 490.0	
Fuel and purchased energy expenses:				
PJM Platform	**$ (205.5)**		$ (118.7)	
Plants with Power Purchase Agreements	**(12.7)**		(8.7)	
Competitive Supply	**(1,144.9)**		(23.4)	
Other	**(16.0)**		(1.2)	
Total	**$ (1,379.1)**		$ (152.0)	
Revenues less fuel and purchased energy expenses:		**% of Total**		**% of Total**
PJM Platform	**$ 170.2**	**57%**	$ 167.7	49%
Plants with Power Purchase Agreements	**96.5**	**32**	83.8	25
Competitive Supply	**14.4**	**5**	63.6	19

Quarter Ended March 31,		2003			2002	
Other		**16.9**	**6**		22.9	7
Total	**$**	**298.0**	**100%**	$	338.0	100%

PJM Platform

Quarter Ended March 31,		2003		2002
		(In millions)		
Revenues	**$**	**375.7**	$	286.4
Fuel and purchased energy expenses		**(205.5)**		(118.7)
Revenues less fuel and purchased energy	**$**	**170.2**	$	167.7

Revenues

BGE Standard Offer Service

The majority of PJM Platform revenues arise from supplying BGE's standard offer service requirements. Revenues from supplying BGE's standard offer service requirements, including CTC and decommissioning revenues, were about the same in 2003 compared to 2002. Decreases due to approximately 1,200 megawatts of large commercial and industrial customers leaving BGE's standard offer service in the second quarter of 2002 and electing other electric generation suppliers were offset by higher volumes sold to BGE due to colder winter weather.

CTC revenues are impacted by the CTC rates our merchant energy business receives from BGE customers as well as the volumes delivered to BGE customers. The CTC rates decline over the transition period as previously discussed in the *Electric Competition Maryland* section on page 26.

Approximately one-third of the load for large commercial and industrial customers left BGE's standard offer service and elected BGE Home, a subsidiary of Constellation Energy, as their electric generation supplier. Our merchant energy business continues to provide the energy to BGE Home to meet the requirements of these customers under market-based rates. Revenues from BGE Home were $19.5 million in 2003. BGE Home is included in our other nonregulated businesses.

Other PJM Revenues

Other merchant energy revenues in the PJM region increased $66.3 million in 2003 compared to 2002 mostly because of higher sales of power from our owned generation in excess of that used to serve BGE's standard offer service. These sales increased primarily due to higher generation from our generating plants sold into the wholesale market at higher prices due to colder winter weather.

Fuel and Purchased Energy Expenses

Our merchant energy business had higher fuel and purchased energy expenses in the PJM region in 2003 compared to 2002 primarily due to higher generation at our plants and increased purchased energy and capacity expenses because of higher wholesale market prices to serve BGE's standard offer service.

Plants with Power Purchase Agreements

Quarter Ended March 31,		2003		2002
		(In millions)		
Revenues	**$**	**109.2**	$	92.5
Fuel and purchased energy expenses		**(12.7)**		(8.7)

Quarter Ended March 31,	2003	2002
Revenues less fuel and purchased energy	**$ 96.5**	$ 83.8

The increase in revenues in 2003 compared to 2002 primarily was due to the following:

- higher revenues of $9.9 million from Nine Mile Point due to increased availability of Nine Mile Point and higher power prices in the New York region compared to 2002, and
- revenues from the Oleander generating facility that commenced operations in the second half of 2002.

Our merchant energy business had higher fuel and purchased energy expenses in 2003 compared to 2002 primarily due to the Oleander generating facility.

<u>*Competitive Supply*</u>

Quarter Ended March 31,	2003	2002
	(Restated)	
	(In millions)	
Accrual revenues	**$ 1,162.5**	$ 23.2
Mark-to-market revenues	**(3.2)**	63.8
Fuel and purchased energy expenses	**(1,144.9)**	(23.4)
Revenues less fuel and purchased energy	**$ 14.4**	$ 63.6

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

Accrual Revenues and Fuel and Purchased Energy Expenses

Our accrual revenues and fuel and purchased energy expenses increased in 2003 compared to 2002 mostly because of the re-designation of our load-serving activities to accrual, including the adoption of EITF 02-3, combined with increased wholesale accrual origination activities, primarily in Texas and New England, and the acquisitions of NewEnergy and Alliance. We provide the changes in revenues and fuel and purchased energy expenses in 2003 compared to 2002 in the following table.

	2003 *(Restated)* vs. 2002	
Quarter Ended March 31,	**Increases in revenues**	**Increases in fuel and purchased energy expenses**
	(In millions)	
Texas and New England	$ 556.8	$ 574.1
Acquired companies	582.5	547.4
Total increase	$ 1,139.3	$ 1,121.5

2003 *(Restated)* vs. 2002

Fuel and purchased energy expenses were higher than revenues in 2003 for Texas and New England mostly because of the negative impact of volatile gas and power prices in New England and cold northeastern weather and outages at third party plants that required our merchant energy business to purchase power in the wholesale market at higher prices.

Since February 2002, we manage our Texas load-serving activities as a physical delivery business separate from our trading activities and re-designated these activities as non-trading. We believe this designation more accurately reflects the substance of our Texas load-serving physical delivery activities.

At the time of this change in designation, we reclassified the fair value of load-serving contracts and physically delivering power purchase agreements in Texas from "Mark-to-market energy assets and liabilities" to "Other assets and liabilities." The contracts reclassified consisted of gross assets of $78 million and gross liabilities of $15 million, or a net asset of $63 million. We removed the unamortized balance of these assets and liabilities, excluding the costs of any acquired contracts, from our Consolidated Balance Sheets upon adoption of EITF 02-3 in the first quarter of 2003.

In addition, our New England load-serving business consists primarily of contracts to serve the full energy and capacity requirements of retail customers and electric distribution utilities and associated power purchase agreements to supply our customers' requirements. We manage this business primarily to assure profitable delivery of customers' energy requirements rather than as a traditional trading activity. Therefore, we use accrual accounting for New England load-serving transactions and associated power purchase agreements entered into since the second quarter of 2002.

However, prior to EITF 02-3, applicable accounting rules significantly limited the circumstances under which contracts previously designated as a trading activity could be re-designated as non-trading. Therefore, we were required to continue to include contracts entered into before the second quarter of 2002 in our mark-to-market accounting portfolio. We removed these contracts from our "Mark-to-market energy assets and liabilities" and began to account for these contracts under the accrual method of accounting upon the adoption of EITF 02-3 in 2003.

We discuss the implications of EITF 02-3 in more detail in the *Notes to Consolidated Financial Statements* on page 18.

Mark-to-Market Revenues

Mark-to-market revenues include net gains and losses from origination and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section on page 21. We also discuss the implications of EITF 02-3 on the mark-to-market method of accounting in the *Notes to Consolidated Financial Statements* on page 18.

As a result of the nature of our operations and the use of mark-to-market accounting for certain activities, mark-to-market revenues and earnings will fluctuate. We cannot predict these fluctuations, but the impact on our revenues and earnings could be material. We discuss our market risk in more detail in the *Market Risk* section in our 2002 Annual Report on Form 10-K. The primary factors that cause fluctuations in our mark-to-market revenues and earnings are:

- the number, size, and profitability of new transactions,
- the number and size of our open derivative positions, and

- changes in the level and volatility of forward commodity prices and interest rates.

Mark-to-market revenues were as follows:

Quarter Ended March 31,

	2003	2002

Quarter Ended March 31,	2003	2002
	(In millions)	
Unrealized revenues		
Origination transactions	**$ 14.2**	$ 9.5
Risk management		
Unrealized changes in fair value	**(17.4)**	53.8
Changes in valuation techniques		0.5
Reclassification of settled contracts to realized	**(44.0)**	(20.9)
Total risk management	**(61.4)**	33.4
Total unrealized revenues	**(47.2)**	42.9
Realized revenues	**44.0**	20.9
Total mark-to-market revenues	**$ (3.2)**	$ 63.8

Revenues from origination transactions represent the initial unrealized fair value of new wholesale energy transactions (including restructurings) at the time of contract execution to the extent permitted by applicable accounting rules. Risk management revenues represent both realized and unrealized gains and losses from changes in the value of our entire portfolio. We discuss the changes in mark-to-market revenues below. We show the relationship between our revenues and the change in our net mark-to-market energy asset later in this section.

Our mark-to-market revenues were and continue to be affected by a decrease in the portion of our activities that is subject to mark-to-market accounting. As discussed in our 2002 Annual Report on Form 10-K, we re-designated our Texas load-serving business as accrual during 2002, and we began to account for new non-derivative origination transactions on the accrual basis rather than under mark-to-market accounting. Beginning January 1, 2003, under EITF 02-3, we no longer record existing non-derivative contracts at fair value.

Mark-to-market revenues decreased $67.0 million during 2003 compared to 2002 mostly because of net losses from risk management activities compared to net gains in the prior year. The decrease in risk management revenues is primarily due to mark-to-market losses on hedges that did not qualify for hedge accounting treatment as discussed in more detail below, and unfavorable changes in regional power prices, price volatility, and other factors in 2003 compared to 2002.

Prior to EITF 02-3, we were required to record all of our New England load serving positions entered into before the second quarter of 2002 and our hedges against those positions on a mark-to-market basis. With EITF 02-3 implementation in the first quarter of 2003, all of the load-serving contracts were converted to accrual accounting. However, several economically effective hedges on these positions did not qualify for accrual hedge accounting treatment under SFAS No. 133 and remained in the mark-to-market portfolio.

In the first quarter of 2003, increasing forward prices shifted value between accrual load-serving positions and associated mark-to-market hedges producing a timing difference in the recognition of earnings on related transactions. As a result, we recorded a $20 million pre-tax loss on the mark-to-market hedges in the first quarter of 2003. We will realize gains on the accrual load-serving positions in cash over the balance of the year, offset by cash losses on the hedges, which we had to mark-to-market this quarter.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts, and in 2002, prior to the implementation of EITF 02-3, were compromised of a combination of derivative and non-derivative (physical) contracts. The non-derivative assets and liabilities primarily relate to load-serving activities originated prior to the shift to accrual accounting in 2002. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We discuss our modeling techniques later in this section.

Mark-to-market energy assets and liabilities consisted of the following:

	March 31, 2003	December 31, 2002

	March 31, 2003	December 31, 2002
	(In millions)	
Current Assets	**$ 114.8**	$ 144.0
Noncurrent Assets	**1,027.0**	1,348.2
Total Assets	**1,141.8**	1,492.2
Current Liabilities	**106.4**	94.1
Noncurrent Liabilities	**951.8**	881.5
Total Liabilities	**1,058.2**	975.6
Net mark-to-market energy asset	**$ 83.6**	$ 516.6

The net asset at March 31, 2003 primarily consists of a PJM generation hedge comprised of a group of options that serve as an economic hedge of the PJM generation portfolio. These options give us the right to sell power at a floor price, which is valuable to our generation operation when market prices are low, and also give us the right to buy power at a capped price, which adds value

when the market prices are high. We have not designated these options as hedges under SFAS No. 133 due to the complexity of qualifying options as effective hedges under the requirements of that standard.

The following are the primary sources of the change in net mark-to-market energy asset during the first quarter of 2003:

Change in Net Mark-to-Market Energy Asset

		(In millions)
Fair value beginning of year		$ 516.6
Changes in fair value recorded as revenues		
Origination transactions	$ 14.2	
Unrealized changes in fair value	(17.4)	
Changes in valuation techniques		
Reclassification of settled contracts to realized	(44.0)	
Total changes in fair value recorded as revenues		(47.2)
Impact of EITF 02-3		(379.4)
Changes in value of exchange-listed futures and options		(4.2)
Net change in premiums on options		(4.7)
Other changes in fair value		2.5
Fair value at March 31, 2003		$ 83.6

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

Origination transactions represent the initial unrealized fair value at the time these contracts are executed to the extent permitted by accounting rules, including EITF 02-3.

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 reflect more accurately the economic value of our contracts.

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

The net mark-to-market energy asset also changed due to the following items recorded in accounts other than revenue:

The impact of EITF 02-3 represents the non-derivative portion of the net asset that was reclassified to accrual accounting effective January 1, 2003 as required by EITF 02-3.

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

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

The settlement terms of the net mark-to-market energy asset and sources of fair value as of March 31, 2003 are as follows:

	Settlement Term							
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**Thereafter**	**Fair Value**
					(In millions)			
Prices provided by external sources (1)	$ (6.7)	$ 11.5	$ (9.1)	$ 15.2	$ 12.6	$ 0.6	$	$ 24.1
Prices based on models	1.0	1.6	(0.1)	(1.1)	12.5	15.7	29.9	59.5
Total net mark-to-market energy asset	$ (5.7)	$ 13.1	$ (9.2)	$ 14.1	$ 25.1	$ 16.3	$ 29.9	$ 83.6

(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 tables above based upon the ability to obtain reliable prices for components of the risks in our contracts from external sources rather than on a contract-by-contract basis. Thus, the portion of long-term contracts that is valued using external price sources is presented under the caption "prices provided by external sources." This is consistent with how we manage our risk, and we believe it provides the best indication of the basis for the valuation of our portfolio. Since we manage our risk on a portfolio basis rather than contract-by-contract, it is not practicable to determine separately the portion of long-term contracts that is included in each valuation category. We describe the commodities, products, and delivery periods included in each valuation category in detail 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 purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2004, but up to 2008, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2004, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms through 2004,
- forward purchases and sales of natural gas, coal and oil for delivery terms through 2005, and
- options for the purchase and sale of natural gas, coal and oil for delivery terms through 2005.

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 origination 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 tables 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 tables 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 tables. However, based upon the nature of the origination 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. 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 tables represent expected future cash flows based on the level of forward prices and volatility factors as of March 31, 2003 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.

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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.

Other

Quarter Ended March 31,

	2003	2002
	(In millions)	
Revenues	**$ 32.9**	$ 24.1
Fuel and purchased energy expenses	**(16.0)**	(1.2)
Revenues less fuel and purchased energy	**$ 16.9**	$ 22.9

We analyze the revenues and fuel and purchased energy expenses of the final category of our merchant energy business below.

Revenues

Our other merchant energy business revenues increased in 2003 compared to 2002 mostly because we had higher revenues from our mid-continent region facilities primarily due to higher output from these facilities because of a more favorable relationship between energy prices and gas costs. This increase was partially offset by lower revenues of $13.8 million from our investments in qualifying facilities and domestic power projects. We discuss our investments in qualifying facilities and domestic power projects in more detail below.

Investments in Qualifying Facilities and Domestic Power Projects

Our merchant energy business holds up to a 50% ownership interest in 28 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 28 projects, 20 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.

The decrease in revenues in 2003 compared to 2002 was due to the following:

- We had lower revenues from our California projects because we reversed our credit reserves that totaled $9.1 million during the first quarter of 2002, as we began receiving payments from the California utilities, which had a positive impact in 2002.
- We had lower revenues from a geothermal project generating at a lower capacity.

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 certain risks and uncertainties in more detail in our *Forward Looking Statements* section in Item 5. Other Information of our March 31, 2003 Quarterly Report on Form 10-Q. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired under the provisions of APB No. 18.

We have an investment in a partnership that owns a geothermal project with a book value of $99.3 million at March 31, 2003. Currently, the project is not generating at its designed capacity. Recently, the project completed well-drilling efforts designed to restore the output of the project, and the project currently is evaluating its level of sustainable output. Provided the project can achieve the necessary level of geothermal resource and output from the recently completed drilling efforts, we expect the project to generate sufficient cash flows over its life to enable us to recover our equity interest in the project. However, should the recently completed well drilling not result in a sufficient geothermal resource, or should future well drilling at this project prove to be unsuccessful or become uneconomic causing us not to make future investments in this partnership, our investment in this partnership could become impaired under the provisions of APB No. 18, and any losses recognized could be material.

The ability to recover our costs in our equity-method investments that own biomass and solar projects is partially dependent upon subsidies from the State of California. Under the California Public Utility Act, subsidies currently exist in that the California Public Utilities Commission (CPUC) requires electric corporations to identify a separate rate component to fund the development of renewable resources technologies, including solar, biomass, and wind facilities. In addition, legislation in California requires that each electric corporation increase its total procurement of eligible renewable energy resources by at least one percent per year so that 20% of its retail sales are procured from eligible renewable energy resources by 2017. The legislation also requires the California Energy Commission to award

supplemental energy payments to electric corporations to cover above market costs of renewable energy.

Given the need for electric power and the desire for renewable resource technologies, we believe California will continue to subsidize the use of renewable energy to make these projects economical to operate. However, should the California legislation fail to adequately support the renewable energy initiatives, our equity-method investments in these types of projects could become impaired under the provisions of APB No. 18, and any losses recognized could be material.

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.

Fuel and Purchased Energy Expenses

Our other merchant energy business fuel and purchased energy expenses increased in 2003 compared to 2002 mostly because we had higher fuel and purchased energy expenses for our mid-continent region facilities primarily due to higher demand for the output of these facilities.

Operations and Maintenance Expenses

Our merchant energy business operations and maintenance expenses increased $13.8 million in 2003 compared to 2002 mostly due to the following:

- An increase of $18.1 million due to the acquisitions of NewEnergy and Alliance.
- An increase of $7.1 million at Nine Mile Point primarily related to higher costs associated with the refueling outage of Unit 1 in 2003 compared to the 2002 refueling outage of Unit 2. Since we own 100% of Unit 1, we incur all outage costs compared to 82% of costs for Unit 2.

These increases were partially offset by lower costs of approximately $10 million due to productivity initiatives associated with our corporate-wide workforce reduction and other productivity programs.

Workforce Reduction Costs

Our merchant energy business recognized $0.4 million in 2003 and $5.0 million in 2002 of expenses associated with our workforce reduction efforts.

We discuss these workforce reduction costs in more detail in the *Notes to Consolidated Financial Statements* on page 10.

Depreciation and Amortization Expense

Merchant energy depreciation and amortization expense decreased $5.8 million in 2003 compared to 2002 mostly because of the adoption of SFAS No. 143. Under SFAS No. 143, a portion of the decommissioning amortization is included as "Accretion of asset retirement obligations" expense beginning in 2003 as discussed below. In addition, we no longer include the expected net future costs of removal as a component of depreciation expense beginning in 2003. These decreases were partially offset by higher depreciation expense of new generating facilities that commenced operations in mid-2002.

Accretion of Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143 that requires the accretion of the asset retirement obligation liability due to the passage of time until the liability is settled. Accordingly, we recognized $10.7 million in accretion expense in the first quarter of 2003. We discuss SFAS No. 143 in the *Notes to Consolidated Financial Statements* on page 17.

Taxes Other Than Income Taxes

Merchant energy taxes other than income taxes increased $5.3 million in 2003 compared to 2002 mostly because of taxes other than income taxes associated with NewEnergy and the new generating facilities.

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Regulated Electric Business

As previously discussed, our regulated electric business was significantly impacted by the July 1, 2000 implementation of customer choice. These changes include BGE's generating assets and related liabilities becoming part of our nonregulated merchant energy business on that date.

BGE's electric rates are frozen in total during the transition period and are unbundled to show separate components for delivery service, transition charges, standard offer services (generation), transmission, universal service, and certain taxes. In addition, 90% of the CTC revenues BGE collects and the portion of its revenues providing for decommissioning costs are included in revenues of the merchant energy business.

As part of the deregulation of electric generation, while total rates are frozen over the transition period, the increasing rates received from customers under standard offer service are offset by declining CTC rates.

Results

Quarter Ended March 31,

	2003	2002
	(In millions)	
Revenues	**$ 486.3**	$ 460.4
Electricity purchased for resale expenses	**(243.6)**	(240.5)
Operations and maintenance expenses	**(53.9)**	(60.8)
Workforce reduction costs	**(0.3)**	(20.9)
Depreciation and amortization	**(44.2)**	(43.8)
Taxes other than income taxes	**(35.3)**	(34.7)
Income from Operations	**$ 109.0**	$ 59.7
Net Income	**$ 50.2**	$ 16.4
Special Items Included in Operations (after-tax)		
Workforce reduction costs	**$ (0.2)**	$ (12.6)

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

Net income from the regulated electric business increased during the quarter ended March 31, 2003 compared to the same period of 2002 mostly because of the following:

- lower workforce reduction costs of $12.4 million after-tax related to our 2002 corporate-wide workforce reduction programs,
- increased distribution sales volumes due to colder winter weather,
- cost reductions in 2003 resulting from our corporate-wide workforce reduction programs and other productivity initiatives, and
- lower interest expense.

Electric Revenues

The changes in electric revenues in 2003 compared to 2002 were caused by:

Quarter Ended March 31,	**2003 vs. 2002**
	(In millions)
Distribution sales volumes	$ 16.8
Standard offer service	2.4
Total change in electric revenues from electric system sales	19.2
Other	6.7
Total change in electric revenues	$ 25.9

Distribution Sales Volumes

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

The percentage changes in our distribution sales volumes, by type of customer, in 2003 compared to 2002 were:

Quarter Ended March 31,	**2003 vs. 2002**
Residential	18.8%
Commercial	4.0
Industrial	(2.1)

During 2003, we distributed more electricity to residential and commercial customers compared to 2002 mostly due to colder winter weather. We distributed less electricity to industrial customers mostly because of lower usage by industrial customers.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative generation supplier as previously discussed.

Standard offer service revenues increased in 2003 compared to 2002 primarily due to colder winter weather partially offset by approximately 1,200 megawatts of large commercial and industrial customers leaving BGE's standard offer service in the second quarter of 2002 and electing other electric generation suppliers.

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 customers.

Our electricity purchased for resale expenses were about the same in 2003 compared to 2002. Increases due to higher volumes purchased because of colder winter weather were offset by large commercial and industrial customers leaving BGE's standard offer service and electing other electric generation suppliers.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses decreased $6.9 million in 2003 compared to 2002 mostly due to cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

Workforce Reduction Costs

BGE's electric business workforce reduction expenses decreased $20.6 million pre-tax, or $12.4 million after-tax, in 2003 compared to 2002 because these programs were substantially completed in 2002. We discuss our workforce reduction efforts in the *Notes to Consolidated Financial Statements* on page 10.

Other Electric Operating Expenses

Regulated other electric operating expenses were about the same in 2003 compared to 2002.

Regulated Gas Business

All BGE customers have the option to purchase gas from other suppliers. To date, customer choice has not had a material effect on our, or BGE's, financial results.

Results

Quarter Ended March 31,	**2003**	**2002**
	(In millions)	
Gas revenues	**$ 303.5**	$ 223.3
Gas purchased for resale expenses	**(203.1)**	(124.3)
Operations and maintenance expenses	**(23.2)**	(23.7)
Depreciation and amortization	**(11.7)**	(12.7)
Taxes other than income taxes	**(9.9)**	(9.3)
Income from operations	**$ 55.6**	$ 53.3
Net Income	**$ 28.6**	$ 27.8

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. The Information by Operating Segment section within the Notes to Consolidated Financial Statements on page 12 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Gas Revenues

The changes in gas revenues in 2003 compared to 2002 were caused by:

Quarter Ended March 31,	**2003 vs. 2002**
	(In millions)

Quarter Ended March 31,	**2003 vs. 2002**
Distribution sales volumes	$ 18.2
Base rates	(0.9)
Weather normalization	(15.7)
Gas cost adjustments	71.9
Total change in gas revenues from gas system sales	73.5
Off-system sales	6.4
Other	0.3
Total change in gas revenues	$ 80.2

Distribution Sales Volumes

The percentage changes in our distribution sales volumes, by type of customer, in 2003 compared to 2002 were:

Quarter Ended March 31,	**2003 vs. 2002**
Residential	31.5%
Commercial	14.3
Industrial	(16.0)

During 2003, we distributed more gas to residential and commercial customers compared to 2002 mostly due to colder winter weather. We distributed less gas to industrial customers mostly because of lower usage by industrial customers.

Base Rates

Base rate revenues were about the same in 2003 compared to 2002.

Weather Normalization

The Maryland PSC allows us to record a monthly adjustment to our gas 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 2002 Annual Report on Form 10-K. However, under market-based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

Delivery service customers are not subject to the gas cost adjustment clauses because we are not selling gas to them. We charge these customers fees to recover the fixed costs for the transportation service we provide. These fees are the same as the base rate charged for gas distributed and are included in gas distribution sales volumes.

During 2003, gas cost adjustment revenues increased compared to 2002 because we sold more gas at a higher price.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order related to our annual gas cost adjustment clause review proceeding that will allow us to recover $1.7 million of a previously established regulatory asset of $9.4 million for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the remaining difference of $7.7 million as disallowed fuel costs in the fourth quarter of 2002. However, we appealed the proposed order. As of the date of this report, the Maryland PSC has not acted on BGE's appeal.

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.

During 2003, revenues from off-system gas sales increased compared to 2002 mostly because the gas we sold off-system was at a higher price, 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 customers.

During 2003, gas costs increased compared to 2002 because we purchased more gas at a higher price.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses were about the same in 2003 compared to 2002.

Other Gas Operating Expenses

Regulated other gas operating expenses were about the same in 2003 compared to 2002.

Other Nonregulated Businesses

Results

Quarter Ended March 31,

	2003	2002
	(In millions)	
Revenues	**$ 155.6**	$ 120.4
Operating expenses	**(143.0)**	(116.4)
Depreciation and amortization	**(4.3)**	(3.9)
Taxes other than income taxes	**(1.0)**	(1.0)
Net gain on sales of investments and other assets	**13.7**	257.1
Income from Operations	**$ 21.0**	$ 256.2
Net Income	**$ 8.7**	$ 157.4
Special Items Included in Operations (after-tax)		
Gains on sale of investments and other assets	**$ 8.3**	$ 164.2

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

During the quarter ended March 31, 2003, net income from our other nonregulated businesses decreased compared to the same period of 2002 mostly because we recognized a $163.3 million after-tax gain on the sale of our investment in Orion in 2002 that had a positive impact in that period. This decrease was partially offset by the following:

- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001,
- a $1.2 million pre-tax gain on an installment sale of a parcel of real estate, and

- higher net income from BGE Home due to improved performance in their gas and electric commodity programs.

As previously discussed in our 2002 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.

Our remaining real estate projects, which represent approximately 400 acres of land holdings at March 31, 2003, are partially or substantially developed. Our strategy is to hold and in some cases further develop these projects to increase their value. However, if we were to sell these projects in the current market, we may have losses that could be material, although the amount of the losses is hard to predict.

In addition, we initiated a liquidation program for our financial investments operation and expect to sell substantially all of our investments in this operation by the end of 2003. Through March 31, 2003, we liquidated approximately 88% of our investment portfolio since the beginning of 2002.

Consolidated Nonoperating Income and Expenses

Fixed Charges

During the quarter ended March 31, 2003, total fixed charges increased compared to the same period of 2002 mostly because of a higher level of long-term debt at higher interest rates. The majority of this debt was issued at the end of the first quarter of 2002 and used to repay our short-term borrowings that funded our construction program and acquisitions in prior years. In addition, we had lower capitalized interest due to our new generating facilities commencing operations.

During the quarter ended March 31, 2003, total fixed charges at BGE decreased compared to the same period of 2002 mostly because of a lower level of debt outstanding and lower interest rates.

Income Taxes

During the quarter ended March 31, 2003, our income taxes decreased compared to the same period of 2002 mostly because of the gain on the sale of our investment of Orion in the first quarter of 2002 that increased income taxes in that period.

During the quarter ended March 31, 2003, income taxes at BGE increased compared to the same period of 2002 mostly because of higher taxable income.

Financial Condition

Cash Flows

Cash provided by operations was $245.7 million for the quarter ended March 31, 2003 compared to $434.9 million in 2002.

Cash used in investing activities for the quarter ended March 31, 2003 was $84.6 million compared to cash provided by investing activities of $362.2 million in 2002. The decrease was primarily due to the sale of Orion and Corporate Office Properties Trust that generated

$555.4 million in cash proceeds in 2002, offset in part by lower capital spending in 2003.

Cash used in financing activities for the quarter ended March 31, 2003 was $163.9 million compared to cash provided of $172.6 million in 2002. The decrease was primarily due to the absence of long-term debt issuances and a higher dividend payment, partially offset by lower repayment of debt.

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, and the amount of debt as a component of total capitalization. All Constellation Energy and BGE credit ratings have stable outlooks. At the date of this report, our credit ratings were as follows:

	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	A-
BGE			
Commercial Paper	A-2	P-1	F-1
Mortgage Bonds	A	A1	A+
Senior Unsecured Debt	BBB+	A2	A
Trust Originated Preferred Securities and Preference Stock	BBB	Baa1	A-

Available Sources of Funding

As previously discussed in our 2002 Annual Report on Form 10-K, we decided to sell certain non-core assets to focus on our core strategies. We expect to use the proceeds from the sale of non-core assets to reduce our debt and fund our merchant energy business. We continuously monitor our liquidity requirements and believe that our facilities and access to the capital markets provide sufficient liquidity to meet our business requirements. We discuss our available sources of funding in more detail below.

Constellation Energy

In 2002, Constellation Energy issued $2.5 billion of long-term debt and used the proceeds to repay short-term borrowings and to increase our cash balance. In addition to the cash available, Constellation Energy also has a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At March 31, 2003, we had credit facilities of approximately $1.5 billion as discussed below.

In June 2002, Constellation Energy arranged a $640 million 364-day revolving credit facility and a $640 million three-year revolving credit facility. We use these two facilities to allow issuance of commercial paper and letters of credit along with our previously established $188.5 million revolving credit facility that expires in June 2003.

These facilities can issue letters of credit up to approximately $1.1 billion. As of March 31, 2003, Constellation Energy had $478.9 million in outstanding letters of credit that results in approximately $1.0 billion of unused credit facilities. Constellation Energy also has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

BGE

BGE maintains $200 million in annual committed credit facilities, expiring May through November of 2003, in order to allow commercial paper to be issued. As of March 31, 2003, BGE had no outstanding commercial paper, which results in $200.0 million in unused credit facilities. BGE also has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

Other Nonregulated Businesses

BGE Home Products & Services maintains a program to sell up to $50 million of receivables.

If we can get a reasonable value for our remaining real estate projects and other investments, additional cash may be obtained by selling them. Our ability to sell or liquidate assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made.

Capital Resources

Our business requires a great deal of capital. Our estimated annual amounts for the years 2003 and 2004 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 2003 and 2004 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, and
- the availability of cash from operations.

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section in Item 5. Other Information of our March 31, 2003 Quarterly Report on Form 10-Q.

Calendar Year Estimates	**2003**	**2004**
	(In millions)	
Nonregulated Capital Requirements:		
Merchant energy		

Calendar Year Estimates

	2003	2004
Steam generators	$ 50	$
Environmental controls	15	
Reactor vessel head replacement	10	25
Continuing requirements (including nuclear fuel)	350(A)	340
Total merchant energy capital requirements	425	365
Other nonregulated capital requirements	55	65
Total nonregulated capital requirements	480	430
Utility Capital Requirements:		
Regulated electric	200	205
Regulated gas	55	60
Total utility capital requirements	255	265
Total capital requirements	$ 735	$ 695

(A) Excludes capital requirements and financing costs for the High Desert Power Project, which are estimated to be approximately $90 million for the full year of 2003.

Capital Requirements

Merchant Energy Business

Our merchant energy business will require additional funding for the following:

Costs for replacing the steam generators for Unit 2 at Calvert Cliffs. The 2003 steam generators replacement occurred during the 2003 refueling outage for Unit 2 and was completed in April 2003.

Costs for replacing the reactor vessel heads at Calvert Cliffs. We expect to replace the reactor vessel heads during the 2006 refueling outage for Unit 1 and the 2007 refueling outage for Unit 2.

Continuing requirements, including construction expenditures for improvements to generating plants, nuclear fuel costs, costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NOx) emissions regulations, and enhancements to our information technology infrastructure. We discuss the NOx regulations and timing of expenditures in the *Environmental Matters* section of the *Notes to Consolidated Financial Statements* beginning on page 13.

The above table does not include the financing for the High Desert 830 megawatt gas-fired generation project in California, which is under an operating lease with a term through February 2006. Under the terms of the lease, we are required to make payments that represent all or a portion of the lease balance if we default under the lease.

Under certain circumstances, we may be required to either post cash collateral equal to the outstanding lease balance or we may elect to purchase the property for the outstanding lease balance. At any time during the term of the lease we have the right to pay off the lease and acquire the asset from the lessor. At March 31, 2003, the outstanding lease balance plus contractual obligations and other committed expenses was $550.0 million, or the estimated cost of the project.

Our wholly owned subsidiary, High Desert Power Project LLC, supervised the construction of, and is leasing, the High Desert project from High Desert Power Trust, an independent special purpose entity (SPE) created to own and lease the project to our subsidiary. Neither Constellation Energy nor any affiliate owns any equity or other interest in High Desert Power Trust, which is owned by a consortium of banks and other financial institutions. We provide a guarantee of High Desert Power Project LLC's obligations to the Trust.

The High Desert Power Project uses an off-balance sheet financing structure through this SPE and currently qualifies as an operating lease. As an operating lease, we do not record any assets or debt associated with the project in our Consolidated Balance Sheets. In January 2003, the FASB issued Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*, that will impact the accounting for, but not the cash flows associated with, our High Desert operating lease and the related SPE. Under the interpretation and current lease structure, we will be required to consolidate the SPE in our Consolidated Balance Sheets as of July 1, 2003, which is the effective date of FIN 46. Had we consolidated this project at March 31, 2003, we would have recorded approximately $508.9 million of development, construction, and capitalized financing costs as an asset and the related financial obligations as a liability in our Consolidated Balance Sheets. We discuss FIN 46 in more detail in *Notes to Consolidated Financial Statements* on page 16.

The lease with the Trust contains several events of default that are commonly found in financings of this type, including failure to make all payments when due, failure to comply with all covenants, violation of material representations and warranties and change of control. In addition, several events of default are applicable to us as guarantor, including defaults in other material financing agreements and failure to own 100% of BGE's common stock.

At the conclusion of the lease term in 2006, we have the following options:

- renew the lease upon approval of the lessor,
- elect to purchase the property for a price equal to the lease balance at the end of the term, or
- request the lessor to sell the property.

If the lessor sells the property, we guarantee the payment of any difference between the sale proceeds and the lease balance at the time of the sale up to a maximum amount of approximately 83% of such lease balance. The lease balance at the end of the term is currently estimated to be $550.0 million, which represents the estimated cost of the project.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities.

Funding for Capital Requirements

Merchant Energy Business

Funding for the expansion of our merchant energy business is expected from internally generated funds. We also have available sources from commercial paper issuances, issuances of long-term debt and equity, leases, and other financing activities.

The projects that our merchant energy business develops typically require substantial capital investment. Most of the projects recently constructed were funded through corporate borrowings by Constellation Energy. Many of the qualifying facilities and independent power projects that we have an interest in are financed primarily with non-recourse debt that is repaid from the project's cash flows. This debt is collateralized by interests in the physical assets, major project contracts and agreements, cash accounts and, in some cases, the ownership interest in that project.

We expect to fund acquisitions with a mixture of debt and equity with an overall goal of maintaining a strong investment grade credit profile.

BGE

Funding for utility capital expenditures is expected from internally generated funds. During 2003, we expect our regulated utility business to generate significant cash flow from operations. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust securities, or preference stock, and/or from time to time equity contributions from Constellation Energy. BGE also participates in a cash pool administered by Constellation Energy as discussed in the *Notes to Consolidated Financial Statements* section on page 19.

Other Nonregulated Businesses

Funding for our other nonregulated businesses is expected from internally generated funds, commercial paper issuances, issuances of long-term debt of Constellation Energy, sales of securities and assets, and/or from time to time equity contributions from Constellation Energy. BGE Home Products & Services can continue to fund capital requirements through sales of receivables.

Our ability to sell or liquidate securities and non-core assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made. We discuss our remaining non-core assets and market conditions in the *Results of Operations Other Nonregulated Businesses* section on page 41.

Committed Amounts

Our total contractual and contingent obligations as of March 31, 2003 are shown in the following table:

	Payments/Expiration				
	2003	**2004-2005**	**2006-2007**	**Thereafter**	**Total**
			(In millions)		
Contractual Obligations					
Short-term borrowings	$ 12.4	$	$	$	$ 12.4
Nonregulated long-term debt[1]	5.6	315.8	620.8	2,206.1	3,148.3
BGE long-term debt[1]	149.4	194.7	591.4	829.7	1,765.2
BGE preference stock				190.0	190.0
Fuel and transportation	509.3	357.5	143.2	101.3	1,111.3
Purchased capacity and energy[2]	960.6	1,029.2	365.3	306.7	2,661.8
Operating leases	22.9	79.8	40.2	151.3	294.2
Capital and other commitments[3]	37.1	32.4	24.3	215.3	309.1
Total contractual obligations	$ 1,697.3	$ 2,009.4	$ 1,785.2	$ 4,000.4	$ 9,492.3
Contingent Obligations					
Letters of credit	$ 468.5	$ 10.4	$	$	$ 478.9
Guarantees - competitive supply[4]	2,345.3	232.6	40.8	178.8	2,797.5
Other guarantees, net[5]	5.2	6.0	602.9	242.3	856.4
Total contingent obligations	$ 2,819.0	$ 249.0	$ 643.7	$ 421.1	$ 4,132.8
Total obligations	$ 4,516.3	$ 2,258.4	$ 2,428.9	$ 4,421.5	$ 13,625.1

1 *Amounts reflected in long-term debt maturities do not include $394.4 million investors may require us to repay early through put options and remarketing features.*

2 *Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including the fixed payment portions related to capacity payments under tolling contracts that were previously included in mark-to-market assets and liabilities prior to EITF 02-3.*

3 *Amounts related to capital expenditures are included for applicable years in our capital requirements table.*

4

While the face amount of these guarantees is $2,797.5 million, we do not expect to fund the full amount as our calculation of the fair value of obligations covered by these guarantees was $812.7 million at March 31, 2003.

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Other guarantees in the above table are shown net of liabilities recorded at March 31, 2003 in our Consolidated Balance Sheets. The 2006 amount shown in the table primarily relates to our maximum guarantee of $600 million for the High Desert lease.

While we included our contingent obligations in the table on the previous page, these amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent guarantees from one Constellation entity for another. We do not expect to fund the full amounts under the letters of credit and guarantees. Specifically, the $2,797.5 million guarantees competitive supply represent the face amount of these guarantees. However, we do not expect to fund the full amount, as our calculation of the fair value of obligations covered by these guarantees was $812.7 million at March 31, 2003.

Lease payments under the High Desert operating lease are reflected in "Other guarantees, net" in the table. The lease balance at the end of the 2006 lease term is currently estimated to be $550.0 million.

Liquidity Provisions

We have certain agreements that contain provisions that would require additional collateral upon significant credit rating decreases in the Senior Unsecured Debt of Constellation Energy. Decreases in Constellation Energy's credit ratings would not trigger an early payment on any of our credit facilities. However, under counterparty contracts related to our origination and risk management operation, where we are obligated to post collateral, we estimate that we would have additional collateral obligations based on downgrades to the following credit ratings for our Senior Unsecured Debt:

Credit Ratings Downgraded	Level Below Current Rating	Incremental Obligations	Cumulative Obligations
		(In millions)	
BBB/Baa2	1	$ 46	$ 46
BBB-/Baa3	2	124	170
Below investment grade	3	525	695

At March 31, 2003, we had approximately $1.2 billion of unused credit facilities and $612.2 million of cash available to meet these potential requirements. However, based on market conditions and contractual obligations at the time of such a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, and which could be material.

In many cases, customers of our origination 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.

The credit facilities of Constellation Energy and BGE have limited material adverse change clauses that only consider a material change in financial condition and are not directly affected by decreases in credit ratings. If these clauses are violated, the lending institutions can decline making new advances or issuing new letters of credit, but cannot accelerate existing amounts outstanding. The long-term debt indentures of Constellation Energy and BGE do not contain material adverse change clauses or financial covenants.

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, 2003, the debt to capitalization ratios as defined in the credit agreements were no greater than 58%.

A BGE credit facility of $50.0 million that expires in August 2003 requires BGE to maintain a ratio of debt to capitalization equal to or less than 70%. At March 31, 2003, the debt to capitalization ratio for BGE as defined in the credit agreement was 51%. At March 31, 2003, no amount is outstanding under this facility.

Failure by Constellation Energy, or BGE, to comply with these covenants could result in the maturity of the debt outstanding under these facilities being accelerated. The credit facilities of Constellation Energy contain usual and customary cross-default provisions that apply to defaults on debt by Constellation Energy and certain subsidiaries over a specified threshold. Certain BGE credit facilities also contain usual and customary cross-default provisions that apply to defaults on debt by BGE over a specified threshold. The indentures pursuant to which BGE has issued and outstanding mortgage bonds and subordinated debentures provide that a default under any debt instrument issued under the relevant indenture may cause a default of all debt outstanding under such indenture.

Constellation Energy also provides credit support to Calvert Cliffs and Nine Mile Point to ensure these plants have funds to meet expenses and obligations to safely operate and maintain the plants.

Other Matters

Environmental Matters

We are subject to federal, state, and local laws and regulations that work to improve or maintain the quality of the environment. If certain substances were disposed of, or released at any of our properties, whether currently operating or not, these laws and regulations require us to remove or remedy the effect on the environment. This includes Environmental Protection Agency Superfund sites.

You will find details of our environmental matters in the *Environmental Matters* section of the *Notes to Consolidated Financial Statements* beginning on page 13 and in our 2002 Annual Report on Form 10-K in *Item 1. Business Environmental Matters.* These details include financial information. Some of the information is about costs that may 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 16.

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 the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. 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 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.

As noted herein, we identified an error in the reporting of certain revenues and expenses in the quarter ended March 31, 2003. This error occurred in spite of the existence of effective controls due to an unusual set of circumstances, including a significant operational change in the New England market's design coupled with the implementation of the significant accounting change mandated by EITF 02-3. As a result, large increases in revenues and expenses anticipated from the change in accounting delayed detection of the error. Ultimately, our internal controls detected this error. Nonetheless, we have enhanced certain processes in response to this error.

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-14(c) and 15d-14(c) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Constellation Energy's and BGE's disclosure controls and procedures are effective, in that they provide reasonable assurance that such officers are alerted on a timely basis to material information relating to Constellation Energy and BGE that is required to be included in Constellation Energy's and BGE's periodic filings under the Exchange Act.

Since the Evaluation Date, there have been no significant changes in either Constellation Energy's or BGE's internal controls or in other factors that could significantly affect such controls.

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SIGNATURE

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

CONSTELLATION ENERGY GROUP, INC.
(Registrant)

BALTIMORE GAS AND ELECTRIC COMPANY
(Registrant)

Date: July 30, 2003 /s/ E. FOLLIN SMITH

E. Follin Smith,
Senior Vice President on behalf of each Registrant
and as Principal Financial Officer of each Registrant

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Constellation Energy Group, Inc.
Certifications

I, Mayo A. Shattuck III, certify that:

1. I have reviewed this amended quarterly report on Form 10-Q of Constellation Energy Group, Inc. (as so amended, "this quarterly report");

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

July 30, 2003

/s/ MAYO A. SHATTUCK III

Chairman of the Board, Chief Executive Officer and President

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Constellation Energy Group, Inc.
Certifications

I, E. Follin Smith, certify that:

1. I have reviewed this amended quarterly report on Form 10-Q of Constellation Energy Group, Inc. (as so amended, "this quarterly report");

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

July 30, 2003

/s/ E. FOLLIN SMITH

Senior Vice President and Chief Financial Officer

Baltimore Gas and Electric Company
Certifications

I, Frank O. Heintz, certify that:

1. I have reviewed this amended quarterly report on Form 10-Q of Baltimore Gas and Electric Company (as so amended, "this quarterly report");

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

July 30, 2003

/s/ FRANK O. HEINTZ

President and Chief Executive Officer

Baltimore Gas and Electric Company
Certifications

I, E. Follin Smith, certify that:

1. I have reviewed this amended quarterly report on Form 10-Q of Baltimore Gas and Electric Company (as so amended, "this quarterly report");

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

    a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

    c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

July 30, 2003

/s/ E. FOLLIN SMITH

Senior Vice President and Chief Financial Officer