

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.
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<b>1-12869</b>	<b>CONSTELLATION ENERGY GROUP, INC.</b>	<b>52-1964611</b>
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<b>1-1910</b>	<b>BALTIMORE GAS AND ELECTRIC COMPANY</b>	<b>52-0280210</b>
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**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 ☐    No ☐

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

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

# Edgar Filing: CONSTELLATION ENERGY GROUP INC - Form 10-Q/A

## 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.

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### 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
	<i>(Restated)</i>	
	<i>(In millions, except per share amounts)</i>	
<b>Revenues</b>		
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
<b>Expenses</b>		
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

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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)

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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)
<b>Comprehensive (Loss) Income</b>	<b>\$ (157.7)</b>	<b>\$ 26.0</b>

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
<i>(In millions)</i>		
<b>Assets</b>		
<b>Current Assets</b>		
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
<b>Investments and Other Assets</b>		
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

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	March 31, 2003*	December 31, 2002
<b>Property, Plant and Equipment</b>		
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
<b>Deferred Charges</b>		
Regulatory assets (net)	301.0	405.7
Other	133.4	136.0
Total deferred charges	434.4	541.7
<b>Total Assets</b>	<b>\$ 15,063.3</b>	<b>\$ 14,128.9</b>

\* 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

Constellation Energy Group, Inc. and Subsidiaries

	March 31, 2003*	December 31, 2002
<i>(In millions)</i>		
<b>Liabilities and Equity</b>		
<b>Current Liabilities</b>		
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

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	March 31, 2003*	December 31, 2002
<b>Deferred Credits and Other Liabilities</b>		
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
<hr/>		
Total deferred credits and other liabilities	3,712.7	3,284.9
<hr/>		
<b>Long-term Debt</b>		
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)
<hr/>		
Total long-term debt	4,612.7	4,613.9
<hr/>		
Minority Interests	107.0	105.3
BGE Preference Stock Not Subject to Mandatory Redemption	190.0	190.0
<hr/>		
<b>Common Shareholders' Equity</b>		
Common stock	2,086.4	2,078.9
Retained earnings	1,802.1	1,977.6
Accumulated other comprehensive loss	(220.5)	(194.2)
<hr/>		
Total common shareholders' equity	3,668.0	3,862.3
<hr/>		
<b>Commitments, Guarantees, and Contingencies (see Notes)</b>		
<hr/>		
Total Liabilities and Equity	\$ 15,063.3	\$ 14,128.9
<hr/>		

\* 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
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**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
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**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
<b>Net (Decrease) Increase in Cash and Cash Equivalents</b>	<b>(2.8)</b>	<b>969.7</b>
<b>Cash and Cash Equivalents at Beginning of Period</b>	<b>615.0</b>	<b>72.4</b>
<b>Cash and Cash Equivalents at End of Period</b>	<b>\$ 612.2</b>	<b>\$ 1,042.1</b>

*See Notes to Consolidated Financial Statements.**Certain prior-period amounts have been reclassified to conform with the current period's presentation.***CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)***Baltimore Gas and Electric Company and Subsidiaries**Three Months Ended March 31,*

	2003	2002
<i>(In millions)</i>		
<b>Revenues</b>		
Electric revenues	\$ 486.3	\$ 460.4
Gas revenues	303.5	223.3
Total revenues	789.8	683.7
<b>Expenses</b>		
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
<b>Income from Operations</b>	<b>164.6</b>	<b>113.0</b>
<b>Other Income</b>	<b>0.3</b>	<b>1.3</b>
<b>Fixed Charges</b>		
Interest expense	30.0	36.5
Allowance for borrowed funds used during construction	(0.5)	(0.4)
Total fixed charges	29.5	36.1

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Three Months Ended March 31,

	2003	2002
<b>Income Before Income Taxes</b>	<b>135.4</b>	<b>78.2</b>
<b>Income Taxes</b>	<b>53.6</b>	<b>31.0</b>
<b>Net Income</b>	<b>81.8</b>	<b>47.2</b>
<b>Preference Stock Dividends</b>	<b>3.3</b>	<b>3.3</b>
<b>Earnings Applicable to Common Stock</b>	<b>\$ 78.5</b>	<b>\$ 43.9</b>

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
<i>(In millions)</i>		
<b>Assets</b>		
<b>Current Assets</b>		
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
<b>Total current assets</b>	<b>902.2</b>	<b>961.7</b>
<b>Other Assets</b>		
Receivable, affiliated company	139.7	63.3
Other	85.7	85.9
<b>Total other assets</b>	<b>225.4</b>	<b>149.2</b>
<b>Utility Plant</b>		
Plant in service		
Electric	3,457.4	3,422.3

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

\* Unaudited

See Notes to Consolidated Financial Statements.

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

**CONSOLIDATED BALANCE SHEETS**

*Baltimore Gas and Electric Company and Subsidiaries*

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

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March 31,  
2003\*

December 31,  
2002

<b>Deferred Credits and Other Liabilities</b>		
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
<b>Long-term Debt</b>		
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
<b>Common Shareholder's Equity</b>		
Common stock	912.2	912.2
Retained earnings	628.0	549.5
Total common shareholder's equity	1,540.2	1,461.7
<b>Commitments, Guarantees, and Contingencies (see Notes)</b>		
<b>Total Liabilities and Equity</b>	<b>\$ 4,796.5</b>	<b>\$ 4,779.9</b>

\* 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 STATEMENTS OF CASH FLOWS (UNAUDITED)

*Baltimore Gas and Electric Company and Subsidiaries*

*Three Months Ended March 31,*

	2003	2002
<b>(In millions)</b>		
<b>Cash Flows From Operating Activities</b>		
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
<b>Cash Flows From Investing Activities</b>		
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)
<b>Cash Flows From Financing Activities</b>		
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
<i>(In millions)</i>			
<b>Revenues</b>			
Nonregulated revenues	\$ 1,828.4	\$ (282.9)	\$ 1,545.5
Regulated electric revenues	486.3		486.3
Regulated gas revenues	298.2		298.2
<b>Total revenues</b>	<b>2,612.9</b>	<b>(282.9)</b>	<b>2,330.0</b>
<b>Expenses</b>			
	2,256.4	(282.9)	1,973.5

*Three Months Ended March 31, 2003*

<b>Operating expenses</b>			
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
<b>Total expenses</b>			
	2,451.0	(282.9)	2,168.1
<b>Net Gain on Sales of Investments and Other Assets</b>			
	13.7		13.7
<b>Income from Operations</b>			
	\$ 175.6	\$	\$ 175.6
<b>Income Before Cumulative Effects of Changes in Accounting Principles</b>			
	\$ 67.0	\$	\$ 67.0
<b>Cumulative Effects of Changes in Accounting Principles</b>			
	(198.4)		(198.4)
<b>Net Loss</b>			
	\$ (131.4)	\$	\$ (131.4)
<b>Loss Applicable to Common Stock</b>			
	\$ (131.4)	\$	\$ (131.4)

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

*Three Months Ended March 31, 2003*

	<b>As Previously Reported</b>	<b>Adjustment</b>	<b>Restated</b>
<i>(in millions)</i>			
Unaffiliated revenues	\$ 1,672.8	\$ (282.9)	\$ 1,389.9
Intersegment revenues	287.2		287.2
<b>Total revenues</b>			
	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,**

	<b>2003</b>	<b>2002</b>
<i>(In millions, except per share amounts)</i>		
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
<b>(Loss) earnings per share:</b>		
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**



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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.

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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)
<hr/>		
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
<i>For the three months ended March 31,</i>						
	<i>(In millions)</i>					
<b>2003 (Restated)</b>						
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

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	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				
	2004- 2005	2006- 2007	Thereafter	Total
2003				

*(In millions)*

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### 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
<hr/>							
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.

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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<sub>2</sub> (sulfur dioxide), NO<sub>x</sub> (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 NO<sub>x</sub>. The EPA rule requires states to implement controls sufficient to meet their NO<sub>x</sub> budget by May 30, 2004. However, the Northeast states decided to require compliance in 2003. Coal-fired power plants are a principal target of NO<sub>x</sub> reductions under this initiative.

Many of our generation facilities are subject to NO<sub>x</sub> 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.

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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 68<sup>th</sup> 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 68<sup>th</sup> Street Dump site. In April 2003, EPA re-proposed the 68<sup>th</sup> 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.

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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.

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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.

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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
<i>(In millions)</i>			
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
			16

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.

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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
<i>(In millions)</i>			
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.

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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.

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## 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.

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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

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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

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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,

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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

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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,

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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.

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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

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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

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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.

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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.

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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%	
	28	

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

#### 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.

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



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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

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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
	<b>(Restated)</b>	
	<b>(In millions)</b>	
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