CONSTELLATION ENERGY GROUP INC
Form 10-K
March 11, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **DECEMBER 31, 2004**

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

MARYLAND

(States of incorporation)

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

410-783-2800

(Registrants' telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

Title of each class	Name of Each Exchange on Which Registered
Constellation Energy Group, Inc. Common Stock Without Par Value	New York Stock Exchange, Inc. Chicago Stock Exchange, Inc. Pacific Exchange, Inc.
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, based on several obligations, by Baltimore Gas and Electric Company	New York Stock Exchange, Inc.

SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:

Not Applicable

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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

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

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 30, 2004 was approximately $6,391,974,086 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE 176,847,227 SHARES OUTSTANDING ON FEBRUARY 28, 2005.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for Constellation Energy Group, Inc. for the Annual Meeting of Shareholders to be held on May 20, 2005.

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

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Forward Looking Statements

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

- the timing and extent of changes in commodity prices and volatilities for energy and energy related products including coal, natural gas, oil, electricity, nuclear fuel, and emission allowances,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,
- the timing and extent of deregulation of, and competition in, the energy markets, and the rules and regulations adopted on a transitional basis in those markets,
- regulatory or legislative developments that affect deregulation, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,
- the inability of Baltimore Gas and Electric Company (BGE) to recover all its costs associated with providing electric residential customers service during the electric rate freeze period,
- the conditions of the capital markets, interest rates, availability of credit, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and BGE's ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,
- operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,
- the actual outcome of uncertainties associated with assumptions and estimates using judgment when applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and, in the absence of verifiable market prices, the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),
- changes in accounting principles or practices,
- losses on the sale or write down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets, and
- cost and other effects of legal and administrative proceedings that may not be covered by insurance, including environmental liabilities.

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

Changes may occur after that date, and neither Constellation Energy nor BGE assume responsibility to update these forward looking statements.

PART I

Item 1. Business

Overview

Constellation Energy is a North American energy company which includes a merchant energy business and BGE, a regulated electric and gas public utility in central Maryland.

Constellation Energy was incorporated in Maryland on September 25, 1995. On April 30, 1999, Constellation Energy became the holding company for BGE and its subsidiaries. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE.

Our merchant energy business is a competitive provider of energy solutions for a variety of customers. 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) of, and providing other energy products and risk management services for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and commercial and industrial customers.

Our merchant energy business includes:

- a generation operation that owns, operates, and maintains fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities, fuel processing facilities and power projects in the United States,
- a marketing and risk management operation that provides energy products and services primarily to distribution utilities, power generators, and other wholesale customers,
- an electric and gas retail operation that provides energy services to commercial and industrial customers, and
- an operations and maintenance consulting services operation.

BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. BGE was incorporated in Maryland in 1906.

Our other nonregulated businesses:

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

In addition, we own several investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Panamanian distribution facility and in a fund that holds interests in two South American energy projects. We discuss these non-core assets in more detail in *Item 7. Management's Discussion and Analysis Results of Operations* section.

For a discussion of recent events that have impacted us, please refer to *Item 7. Management's Discussion and Analysis Significant Events* section. For a discussion of our strategy, please refer to *Item 7. Management's Discussion and Analysis Strategy* section. For a discussion of the seasonality of our business, please refer to *Item 7. Management's Discussion and Analysis Business Environment* section.

Constellation Energy maintains a website at constellation.com where copies of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments may be obtained free of charge. These reports are posted on our website the same day they are filed with the SEC. The SEC maintains a website (sec.gov), where copies of our filings may be obtained free of charge. The website address for BGE is bge.com. These website addresses are inactive textual references and the contents of these websites are not part of this Form 10-K.

In addition, the website for Constellation Energy includes copies of our Corporate Governance Guidelines, Principles of Business Integrity, Corporate Compliance Program and Insider Trading Policy, and the charters for the Audit, Compensation and Nominating, and Corporate Governance Committees of the Board of Directors. Copies of each of these documents may be printed from the website or may be obtained from Constellation Energy upon written request to the Corporate Secretary.

The Principles of Business Integrity is a code of ethics which applies to all of our directors, officers, and employees, including the chief executive officer, chief financial officer, and chief accounting officer. We will post any amendments to, or waivers from, the Principles of Business Integrity applicable to our chief executive officer, chief financial officer, or chief accounting officer on our website.

Operating Segments

The percentages of revenues, net income, and assets attributable to our operating segments are shown in the tables below. We present information about our operating segments, including certain special items, in *Note 3 to Consolidated Financial Statements*.

	Unaffiliated Revenues			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2004	75%	16%	6%	3%
2003	67	20	7	6
2002	35	42	12	11

	Net Income (1)			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2004	75%	22%	4%	(1)%
2003	66	23	9	2
2002	47	19	6	28

	Total Assets			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2004	71%	20%	7%	2%
2003	67	23	7	3
2002	65	24	7	4

(1) Excludes loss on discontinued operations in 2004 and cumulative effects of changes in accounting principles in 2003 as discussed in more detail in *Item 8. Financial Statements and Supplementary Data*.

Merchant Energy Business

Introduction

Our merchant energy business integrates electric generation assets with the marketing and risk management of energy and energy-related commodities, allowing us to manage energy price risk over geographic regions and time.

Constellation Energy Commodities Group (formerly known as Constellation Power Source), our wholesale marketing and risk management operation, dispatches the energy from our generating facilities and facilities with which we have power purchase agreements, manages the risks associated with selling the output and obtaining non-nuclear fuels, and enters into transactions to meet customers' energy and risk management requirements. Constellation NewEnergy, our electric and gas retail operation, provides electricity, natural gas, transportation, and other energy services to commercial and industrial customers.

Constellation Generation Group, our merchant generation operation, oversees the ownership, operations, maintenance, and performance of our fossil and nuclear generation and fuel processing facilities. Our generation capacity supports our wholesale and retail operations by providing a source of reliable power supply that provides a physical hedge for some of our load-serving activities.

Our merchant energy business:

- provided service to distribution utilities, municipalities, and commercial and industrial customers with approximately 31,000 megawatts (MW) of peak load in the aggregate during 2004,
- provided approximately 279,000 million British Thermal Units (mmBTUs) of natural gas to commercial and industrial customers during 2004, and
- managed approximately 12,530 MW of generation capacity.

We analyze the results of our merchant energy business as follows:

- Mid-Atlantic Region our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region for which the output is primarily used to serve BGE. This also includes active portfolio management of the generating assets and other physical and financial contractual arrangements, as well as other PJM competitive supply activities.
- Plants with Power Purchase Agreements our generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point), R.E. Ginna Nuclear Plant (Ginna), Oleander, University Park, and High Desert generating facilities.
- Wholesale Competitive Supply our marketing and risk management operation that provides energy products and services outside the Mid-Atlantic Region primarily to distribution utilities, power generators, and other wholesale customers.
- Retail Competitive Supply our operation that provides electric and gas energy products and services to commercial and industrial customers.
- Other our investments in qualifying facilities and domestic power projects and our operations and maintenance consulting services.

We present details about our generating properties in *Item 2. Properties.*

Mid-Atlantic Region

We own 6,418 MW of fossil, nuclear and hydroelectric generation capacity in the Mid-Atlantic Region. The output of these plants is managed by our wholesale marketing and risk management operation and is hedged through a combination of power sales to wholesale and retail market participants.

BGE transferred all of these facilities to our merchant energy generation subsidiaries on July 1, 2000 as a result of the implementation of electric customer choice and competition among suppliers in Maryland, except for the Handsome Lake project that commenced operations in mid-2001. The assets transferred from BGE are subject to the lien of BGE's mortgage.

Our merchant energy business provides standard offer service to BGE as discussed in the *Baltimore Gas and Electric Company Standard Offer Service* section. Our merchant energy business meets the load-serving requirements of various contracts using the output from the Mid-Atlantic Region and from purchases in the wholesale market. For 2004, the peak load supplied to BGE was approximately 4,100 MW.

Plants with Power Purchase Agreements

We own 3,855 MW of nuclear and natural gas/oil generation capacity with power purchase agreements for their output. Our facilities with power purchase agreements consist of:

- the Nine Mile Point facility,
- the Ginna facility, which was acquired in June 2004,
- the High Desert facility,
- the Oleander facility, and
- the University Park facility.

We own 100% of Nine Mile Point Unit 1 (609 MW) and 82% of Unit 2 (941 MW). The remaining interest in Nine Mile Point Unit 2 is owned by the Long Island Power Authority. Unit 1 entered service in 1969 and Unit 2 in 1988. Nine Mile Point is located within the New York Independent System Operator (NYISO) region.

We sell 90% of our share of Nine Mile Point's output to the former owners of the plant at an average price of nearly $35 per megawatt-hour (MWH) under agreements that terminate between 2009 and 2011. The agreements are unit contingent (if the output is not available because the plant is not operating, there is no requirement to provide output from other sources). The remaining 10% of Nine Mile Point's output is managed by our wholesale marketing and risk management operation and sold into the wholesale market.

After termination of the power purchase agreements, a revenue sharing agreement with the former owners of the plant will begin and continue through 2021. Under this agreement, which applies only to Unit 2, a predetermined price is compared to the market price for electricity. If the market price exceeds the strike price, then 80% of this excess amount is shared with the former owners of the plant. The revenue sharing agreement is unit contingent and is based on the operation of the unit.

We exclusively operate Unit 2 under an operating agreement with the Long Island Power Authority. The Long Island Power Authority is responsible for 18% of the operating costs (and decommissioning costs) of Unit 2 and has representation on the Nine Mile Point Unit 2 management committee which provides certain oversight and review functions.

In May 2004, we filed an application with the Nuclear Regulatory Commission (NRC) for a 20-year license extension for both units at Nine Mile Point. The license on Nine Mile Point's Unit 1 expires in 2009 and in 2026 on Unit 2. We must demonstrate that we can ensure that the units will continue to perform their intended functions through the renewal period. The NRC will also consider the impact of the 20-year license extension on the environment. We expect approval of our application by early 2007 and have assumed license extension for purposes of recording depreciation expense and asset retirement obligations. However, we cannot predict the actual timing of the NRC's decision, or the impact of the decision, if any, on our financial results. If we do not receive the license extension, we will not be able to operate the Nine Mile Point units beyond 2009 and 2026.

In June 2004, we completed our purchase of the Ginna nuclear facility which is located in Ontario, New York from Rochester Gas & Electric Corporation (RG&E). Ginna consists of a 495 megawatt reactor that entered service in 1970 and is licensed to operate until 2029. The acquisition includes a long-term unit contingent power purchase agreement under which we sell 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per MWH. The remaining 10% of the plant's output is managed by our wholesale marketing and risk management operation and sold into the wholesale market.

The High Desert facility 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 which 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 until December 2010, the project will provide energy exclusively to the CDWR.

We have sold portions of the output of the Oleander and University Park facilities ranging from 50% to 100% under tolling contracts for terms ending in 2005 through 2009. Under these tolling contracts, our respective counterparties will pay a fixed amount per month and have the right, but not the obligation, to purchase power from us at prices linked to the variable fuel and other costs of production.

Competitive Supply

We are a leading supplier of energy products and services in North America to wholesale customers and retail commercial and industrial customers. We discuss our acquisitions of retail commercial and industrial operations in *Note 15 to the Consolidated Financial Statements*. During 2004, our competitive supply activities served approximately 22,400 MW of peak load and approximately 279,000 mmBTUs of natural gas. Our competitive supply activities also include 2,015 MW from our Rio Nogales, Holland Energy, Big Sandy, and Wolf Hills natural gas-fired generating facilities. These four facilities are not sold forward under long-term agreements, and their output is used to serve customer requirements.

Wholesale and Retail Load-Serving Activities

We structure transactions that serve the full energy and capacity requirements of various customers outside the PJM region such as distribution utilities, municipalities, cooperatives, and retail aggregators that do not own sufficient generating capacity or in-house supply functions to meet their own load requirements. We also structure transactions to supply full energy and capacity requirements and provide natural gas, transportation, and other energy products and services to retail commercial and industrial customers.

These activities typically occur in regional markets in which end user customers' electricity rates have been deregulated and thereby separated from the cost of generation supply. These markets include:

- the Northeast (New England and New York),
- the Midwest region,
- the West region (Texas and California), and

certain areas of Canada.

Contracts with these customers generally extend from one to ten years, but some can be longer. To meet our customers' load-serving requirements, our merchant energy business obtains energy from various sources, including:

bilateral power purchase agreements with third parties,

our generation assets,

regional power pools, and

tolling contracts with generation companies, which provide us the right, but not the obligation, to purchase power at a price linked to the variable cost of production, including fuel, with terms that generally extend from several months to several years but can be longer.

Portfolio Management

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities we trade energy and energy-related commodities to enable price discovery and facilitate the hedging of our load-serving and other risk management products and services. Within our trading function we allow limited risk-taking activities for profit. These activities are actively managed through daily value at risk and liquidity position limits. We discuss value at risk in more detail in *Item 7. Management's Discussion and Analysis Market Risk.*

These activities involve the use of a variety of instruments, including:

- forward contracts (which commit us to purchase or sell energy commodities in the future),
- swap agreements (which require payments to or from counterparties based upon the difference between two prices for a predetermined contractual (notional) quantity),
- option contracts (which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price), and
- futures contracts (which are exchange traded standardized commitments to purchase or sell a commodity or financial instrument, or make a cash settlement, at a specified price and future date).

Active portfolio management allows our wholesale marketing and risk management operation the ability to:

- manage and hedge its fixed-price purchase and sale commitments,
- provide fixed-price commitments to customers and suppliers,
- reduce exposure to the volatility of cash market prices, and
- hedge fuel requirements at our non-nuclear generation facilities.

Other Competitive Supply Activities

Our wholesale marketing and risk management operation participates in global coal sourcing activities by providing coal for the variable or fixed supply needs of North American and international power generators. In addition, our wholesale marketing and risk management operation provides products and services to upstream (exploration and production) and downstream (transportation and storage) natural gas customers. We also include in our other competitive supply activities the results from our synthetic fuel processing facility in South Carolina.

Other

We hold up to a 50% voting interest in 24 operating energy projects that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities and are either qualifying facilities under the Public Utility Regulatory Policies Act of 1978 or otherwise exempt from, or not subject to, the Public Utility Holding Company Act of 1935. Each electric generating plant sells its output to a local utility under long-term contracts.

We also provide operation and maintenance services, including testing and start-up to owners of electric generating facilities.

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2004 and our generation based on actual output by fuel type in 2004 were as follows:

Fuel	Capacity Owned	Generation
Nuclear	30%	52%
Coal	22	32
Natural Gas	30	10
Oil	6	1
Renewable and Alternative (1)	3	4
Dual (2)	9	1

(1) Includes solar, geothermal, hydro, and biomass.
(2) Switches between natural gas and oil.

We discuss our risks associated with fuel in more detail in *Item 7. Management's Discussion and Analysis Market Risk.*

Nuclear

The output at our nuclear facilities over the past five years (including periods prior to our acquisition of Nine Mile Point and Ginna) is presented in the following table:

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH*	Capacity Factor	MWH	Capacity Factor
	(MWH in millions)					
2004	14.5	96%	12.1	89%	4.3	100%
2003	13.7	93	12.2	90	3.9	90
2002	12.1	82	11.7	87	3.8	89
2001	13.6	92	11.6	86	4.3	100
2000	13.8	83	11.2	83	3.8	88

*represents our proportionate ownership interest

The supply of fuel for nuclear generating stations includes the:

- purchase of uranium (concentrates and uranium hexafluoride),
- conversion of uranium concentrates to uranium hexafluoride,
- enrichment of uranium hexafluoride, and
- fabrication of nuclear fuel assemblies.

Uranium:	We have commitments for sufficient quantities of uranium (concentrates and uranium hexafluoride) to meet 100% of our total requirements through 2006, 63% in 2007, and 35% in 2008. We experienced price increases in 2004 due to the federally designated Russian export agent terminating its contract with one of our key uranium suppliers. These increases are not expected to continue into 2005.
Conversion:	We have commitments providing for the conversion of all of our uranium concentrates into uranium hexafluoride for our nuclear facilities through 2006 and 63% in 2007 and 35% in 2008.
Enrichment:	We have commitments that provide 100% of our uranium enrichment requirements through 2010 and 25% of these requirements in 2011 and 2012.
Fuel Assembly Fabrication:	We have commitments for the fabrication of fuel assemblies for reloads required through 2008 for Nine Mile Point, through 2013 at Calvert Cliffs, and through 2017 for Ginna.

The nuclear fuel markets are competitive, and although prices for uranium and conversion are increasing, we do not anticipate any significant problems in meeting our future requirements.

Storage of Spent Nuclear Fuel Federal Facilities

One of the issues associated with the operation and decommissioning of nuclear generating facilities is disposal of spent nuclear fuel. There are no facilities for the reprocessing or permanent disposal of spent nuclear fuel currently in operation in the United States, and the NRC has not licensed any such facilities. The Nuclear Waste Policy Act of 1982 (NWPA) required the federal government through the Department of Energy (DOE), to develop a repository for the disposal of spent nuclear fuel and high-level radioactive waste.

As required by the NWPA, we are a party to contracts with the DOE to provide for disposal of spent nuclear fuel from our nuclear generating plants. The NWPA and our contracts with the DOE require payments to the DOE of one tenth of one cent (one mill) per kilowatt hour on nuclear electricity generated and sold to pay for the cost of long-term nuclear fuel storage and disposal. We continue to pay those fees into the DOE's Nuclear Waste Fund for Calvert Cliffs, Ginna, and Nine Mile Point. The NWPA and our contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel generated by nuclear generating units no later than January 31, 1998.

The DOE has stated that it will not meet that obligation until 2010 at the earliest. This delay has required that we undertake additional actions to provide on-site fuel storage at Calvert Cliffs, Ginna, and Nine Mile Point, including the installation of on-site dry fuel storage capacity at Calvert Cliffs, as described in more detail below. In 2004, complaints were filed against the federal government in the United States Court of Federal Claims seeking to recover damages caused by the DOE's failure to meet its contractual obligation to begin disposing of spent nuclear fuel by January 31, 1998. These cases are currently stayed, pending litigation in other related cases.

In connection with our purchase of Ginna, all of RG&E's rights and obligations related to recovery of damages from the DOE were assigned to us. However, we have an obligation to reimburse RG&E for up to the first $10 million of any recovered damages. We and RG&E are currently requesting to allow us to replace RG&E as the party in interest in the complaint filed against the federal government by RG&E.

Storage of Spent Nuclear Fuel On-Site Facilities

Calvert Cliffs has a license from the NRC to operate an on-site independent spent fuel storage installation that expires in 2012. We have storage capacity at Calvert Cliffs that will accommodate spent fuel from operations through 2008. In addition, we can expand our temporary storage capacity at Calvert Cliffs to meet future requirements until approximately 2025. Currently, Nine Mile Point and Ginna do not have independent spent fuel storage capacity. Rather, Nine Mile Point's Unit 1 and Ginna have sufficient storage capacity within the plants until 2010. Nine Mile Point's Unit 2 has sufficient storage capacity within the plant until 2012. After that time, independent spent fuel storage capability may need to be developed at each site.

Cost for Decommissioning Uranium Enrichment Facilities

The Energy Policy Act of 1992 contains provisions requiring domestic nuclear utilities to contribute to a fund for decommissioning and decontaminating uranium enrichment facilities that had been operated by DOE. These contributions are generally payable over a 15-year period with escalation for inflation and are based upon the amount of uranium enriched by DOE for each utility through 1992. The 1992 Act provides that these costs are recoverable through utility service rates. BGE is solely responsible for these costs as they relate to Calvert Cliffs. The sellers of the Nine Mile Point plant and the Long Island Power Authority are responsible for the costs relating to the Nine Mile Point plant. The seller of Ginna is responsible for the costs related to that facility.

Cost for Decommissioning
We are obligated to decommission our nuclear plants at the time these plants cease operation. Every two years, the NRC requires us to demonstrate reasonable assurance that funds will be available to decommission the sites. When BGE transferred all of its nuclear generating assets to our merchant energy business, it also transferred the trust fund established to pay for decommissioning Calvert Cliffs. At December 31, 2004, the trust fund assets were $331.9 million.

Under the Maryland Public Service Commission's (Maryland PSC) order regarding the deregulation of electric generation, BGE ratepayers must pay a total of $520 million, in 1993 dollars adjusted for inflation, to decommission Calvert Cliffs through fixed annual collections of approximately $18.7 million until June 30, 2006, and thereafter in an annual amount determined by reference to specified factors. BGE is collecting this amount on behalf of Calvert Cliffs. Any costs to decommission Calvert Cliffs in excess of this $520 million must be paid by Calvert Cliffs. If BGE ratepayers have paid more than this amount at the time of decommissioning, Calvert Cliffs must refund the excess. If the cost to decommission Calvert Cliffs is less than the amount BGE's ratepayers are obligated to pay, Calvert Cliffs may keep the difference.

The sellers of Nine Mile Point transferred a $441.7 million decommissioning trust fund to us at the time of sale. In return, we assumed all liability for the costs to decommission Unit 1 and 82% of the costs to decommission Unit 2. We believe that this amount is adequate to cover our responsibility for decommissioning Nine Mile Point to a greenfield status (restoration of the site so that it substantially matches the natural state of the surrounding properties and the site's intended use). At December 31, 2004, the Nine Mile Point trust fund assets were $492.2 million.

Upon the closing of the Ginna acquisition, the seller transferred $200.8 million in decommissioning funds to us. In return, we assumed all liability for the costs to decommission the unit. We believe that this transfer will be sufficient to cover our responsibility for decommissioning Ginna to a greenfield status. At December 31, 2004, the Ginna trust fund assets were $209.6 million.

Coal
We purchase the majority of our coal for electric generation under supply contracts with mining operators, and we acquire the remainder in the spot or forward coal markets. We believe that we will be able to renew supply contracts as they expire or enter into contracts with other coal suppliers. Our primary coal burning facilities have the following requirements:

	Approximate Annual Coal Requirement (tons)	**Special Coal Restrictions**
Brandon Shores Units 1 and 2 (combined)	3,500,000	Sulfur content less than 1.20 lbs per mmBTU
C. P. Crane Units 1 and 2 (combined)	850,000	Low ash melting temperature
H. A. Wagner Units 2 and 3 (combined)	1,100,000	Sulfur content no more than 1%

Coal deliveries to these facilities are made by rail and barge. The primary source of coal we use is produced from mines located in central and northern Appalachia. The timely delivery of coal together with the maintenance of appropriate levels of inventory is necessary to allow for continued, reliable generation from these facilities.

During 2003, we expanded our coal sources including restructuring our rail contracts, increasing the range of coals we can consume, adding synthetic fuel as an alternate source, and finding potential other coal supply sources including shipments from Columbia, Venezuela, South Africa, and other international sources.

All of the Conemaugh and Keystone plants' annual coal requirements are purchased by the plant operators from regional suppliers on the open market. The sulfur restrictions on coal are approximately 2.3% for the Keystone plant and approximately 5.3% for the Conemaugh plant.

The annual coal requirements for the ACE, Jasmin, and Poso plants, which are located in California, are supplied under contracts with mining operators. The Jasmin and Poso plants are restricted to coal with sulfur content less than 4.0% and ACE is restricted to less than 2.0%.

All of our requirements reflect historical levels. The actual fuel quantities required can vary substantially from historical levels depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements.

Gas

We purchase natural gas, storage capacity, and transportation, as necessary, for electric generation at certain plants. Some of our gas-fired units can use residual fuel oil or distillates instead of gas. Gas is purchased under contracts with suppliers on the spot market and forward markets, including financial exchanges and bilateral agreements. The actual fuel quantities required can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. However, we believe that we will be able to obtain adequate quantities of gas to meet our requirements.

Oil

Under normal burn practices, our requirements for residual fuel oil (No. 6) amount to approximately 1.5 million to 2.0 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor marine terminal for distribution to the various generating plant locations. Also, based on normal burn practices, we require approximately 5.0 million to 6.0 million gallons of distillates (No. 2 oil and kerosene) annually, but these requirements can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. Distillates are purchased from the suppliers' Baltimore truck terminals for distribution to the various generating plant locations. We have contracts with various suppliers to purchase oil at spot prices, and for future delivery, to meet our requirements.

Competition

Market developments over the past several years have changed the nature of competition in the merchant energy business. Certain companies within the merchant energy sector have curtailed their activities or withdrawn completely from the business. However, new competitors (e.g., financial investors) are entering the market. We encounter competition from companies of various sizes, having varying levels of experience, financial and human resources, and differing strategies.

We face competition in the market for energy, capacity, and ancillary services. In our merchant energy business, we compete with international, national, and regional full service energy providers, merchants, and producers to obtain competitively priced supplies from a variety of sources and locations, and to utilize efficient transmission or transportation. We principally compete on the basis of price, customer service, reliability, and availability of our products.

With respect to power generation, we compete in the operation of energy-producing projects, and our competitors in this business are both domestic and international organizations, including various utilities, industrial companies and independent power producers (including affiliates of utilities), some of which have financial resources that are greater than ours.

Difficulties in making competitive assessments of our company arise from states considering different types of regulatory initiatives concerning competition in the power industry. Increased competition that resulted from some of these initiatives in several states contributed in some instances to a reduction in electricity prices and put pressure on electric utilities to lower their costs, including the cost of purchased electricity. While many states continue their support for retail competition and industry restructuring, other states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, other states are reconsidering deregulation.

We believe there is adequate growth potential in the current deregulated market and that further market changes could provide additional opportunities for our merchant energy business. Our wholesale marketing and risk management operation also participates in global coal sourcing activities by providing coal for the variable or fixed supply needs of North American and international power generators. In addition, our wholesale marketing and risk management operation provides products and services to upstream and downstream natural gas customers.

As the economy continues to recover and the market for commercial and industrial supply continues to grow, we have experienced increased competition in our retail commercial and industrial supply activities. The increase in retail competition and the impact of wholesale power prices compared to the rates charged by local utilities may affect the margins that we will realize from our customers. However, we believe that our experience and expertise in assessing and managing risk will help us to remain competitive during volatile or otherwise adverse market circumstances.

Merchant Energy Operating Statistics

	2004	2003	2002	2001	2000
Revenues *(In millions)*					
Mid-Atlantic Fleet	**$ 1,925.6**	$ 1,696.2	$ 1,415.1	$ 1,379.2	$ 731.7
Plants with Power Purchase Agreements	**756.9**	620.0	456.4	70.8	
Competitive Supply Retail	**4,280.0**	2,567.7	312.7		
Competitive Supply Wholesale	**3,353.8**	2,703.9	540.7	233.5	149.6
Other	**73.6**	45.1	56.4	80.5	142.5
Total Revenues	**$ 10,389.9**	$ 7,632.9	$ 2,781.3	$ 1,764.0	$ 1,023.8
Generation *(In millions)* MWH	**55.3**	51.6	44.7	37.4	18.8

Operating statistics do not reflect the elimination of intercompany transactions.

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

Baltimore Gas and Electric Company

BGE is an electric transmission and distribution utility company and a gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. BGE is regulated by the Maryland PSC and Federal Energy Regulatory Commission (FERC) with respect to rates and other aspects of its business.

BGE's electric service territory includes an area of approximately 2,300 square miles. There are no municipal or cooperative wholesale customers within BGE's service territory. BGE's gas service territory includes an area of approximately 800 square miles.

BGE's electric and gas revenues come from many customers residential, commercial, and industrial. In 2004, BGE's largest electric customer provided approximately two percent of BGE's total electric revenues and BGE's largest gas customer provided approximately one percent of BGE's total gas revenues.

Electric Business

Electric Regulatory Matters and Competition

Deregulation

Effective July 1, 2000, electric customer choice and competition among electric suppliers was implemented in Maryland. As a result of the deregulation of electric generation, the following occurred:

- All customers can choose their electric energy supplier.
- BGE provided fixed-price standard offer service for commercial and industrial customers through either June 30, 2002 or June 30, 2004, depending on customer type. For the commercial and industrial customers that did not select an alternative supplier after those time periods, BGE provided a market-based standard offer service. Base rates for commercial and industrial customers were frozen until June 30, 2004.
- Commercial and industrial customers have several service options that fix competitive transition charges (CTC) through June 30, 2006. CTC revenues were provided to allow BGE to recover stranded costs that resulted from the deregulation of BGE's generating assets.
- BGE residential base rates for delivery service will not change before July 2006. While total residential base rates remain unchanged over the initial transition period (July 1, 2000 through June 30, 2006), annual standard offer service rate increases are offset by corresponding decreases in the CTC that BGE receives from its customers.

While BGE does not sell electric commodity to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, regular maintenance, and balancing services.

BGE transferred, at book value, its generating assets and related liabilities to the merchant energy business. At December 31, 2004, BGE remains contingently liable for the $269.8 million outstanding balance for liabilities transferred to the merchant energy business.

Standard Offer Service

BGE provides fixed-price standard offer service for residential customers that do not select an alternative supplier through June 30, 2006. Beginning July 1, 2006, BGE's current obligation to provide fixed-price standard offer service to residential customers ends, and all residential customers that receive their electric supply from BGE will be charged market-based standard offer service rates, as discussed in the *Standard Offer Service Provider of Last Resort (POLR)* section.

BGE provided fixed-price standard offer service for most of its large commercial and industrial customers through June 30, 2002. The large commercial and industrial customers that did not select an alternative supplier were provided market-based standard offer service through June 30, 2004. BGE provided fixed-price standard offer service to its remaining commercial and industrial customers through June 30, 2004. Beginning July 1, 2004, all commercial and industrial customers that receive their electric supply from BGE are charged market-based standard offer service rates, as discussed in the *Standard Offer Service Provider of Last Resort (POLR)* section.

Standard Offer Service Provider of Last Resort (POLR)
BGE is obligated to provide market-based standard offer service to residential customers from July 1, 2006 through May 31, 2010, and for commercial and industrial customers for one, two, or four-year periods beyond June 30, 2004, depending on customer load. The POLR rates charged during these time periods will recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a shareholder return component and an incremental cost component.

Bidding to supply BGE's standard offer service to commercial and industrial customers for one, two, or four-year periods beyond June 30, 2004, and to residential customers beyond June 30, 2006, will occur from time to time through a competitive bidding process approved by the Maryland PSC. Successful bidders, which may include affiliates of Constellation Energy, will execute contracts with BGE for varying terms depending on the load being served under the contract.

We discuss the market risk of our regulated electric business in more detail in *Item 7. Management's Discussion and Analysis Market Risk* section.

Electric Load Management

BGE has implemented various programs for use when system-operating conditions or market economics indicate that a reduction in load would be beneficial. We refer to these programs as active load management programs. These programs include:

- two options for commercial and industrial customers to voluntarily reduce their electric loads,
- air conditioning control for residential and commercial customers, and
- residential water heater control.

These programs generally take effect on summer days when demand and/or wholesale prices are relatively high. These programs had the capability during the 2004 summer to reduce load up to approximately 220 MW.

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains nearly 22,900 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of the PJM Interconnection. Under the PJM Tariff and various agreements, BGE and other market participants can use regional transmission facilities for energy, capacity, and ancillary services transactions including emergency assistance.

We discuss various FERC initiatives relating to wholesale electric markets in more detail in *Item 7. Management's Discussion and Analysis Federal Regulation* section.

Electric Operating Statistics

	2004	2003	2002	2001	2000
Revenues *(In millions)*					
Residential	**$ 1,015.8**	$ 959.0	$ 946.6	$ 885.3	$ 922.6
Commercial					
Excluding Delivery Service	**708.9**	694.2	776.0	903.0	926.2
Delivery Service Only	**78.6**	66.1	33.5		
Industrial					
Excluding Delivery Service	**92.3**	137.0	158.7	218.1	203.6
Delivery Service Only	**21.3**	18.2	10.9		
System Sales	**1,916.9**	1,874.5	1,925.7	2,006.4	2,052.4
Interchange Sales					53.8
Other (A)	**50.8**	47.1	40.3	33.6	29.0
Total	**$ 1,967.7**	$ 1,921.6	$ 1,966.0	$ 2,040.0	$ 2,135.2
Distribution Volumes *(In thousands)* MWH					
Residential	**13,313**	12,754	12,652	11,714	11,675
Commercial					
Excluding Delivery Service	**9,286**	9,937	11,840	14,147	14,042
Delivery Service Only	**5,767**	4,982	2,762		
Industrial					
Excluding Delivery Service	**1,429**	2,556	3,478	4,445	4,476
Delivery Service Only	**2,562**	1,780	997		
Total	**32,357**	32,009	31,729	30,306	30,193
Customers *(In thousands)*					
Residential	**1,072.1**	1,061.7	1,052.3	1,040.5	1,033.4
Commercial	**113.6**	112.1	110.8	110.9	108.9
Industrial	**4.8**	4.9	4.9	5.0	5.0
Total	**1,190.5**	1,178.7	1,168.0	1,156.4	1,147.3

(A) Primarily includes transmission service integration revenues, late payment charges, miscellaneous service fees, and tower leasing revenues.

Operating statistics do not reflect the elimination of intercompany transactions.

"Delivery service only" refers to BGE's delivery of commodity to customers that was purchased by the customer from an alternate supplier.

Gas Business

The wholesale price of natural gas as a commodity is not subject to regulation. All BGE gas customers have the option to purchase gas from alternative suppliers, including subsidiaries of Constellation Energy. BGE continues to deliver gas to all customers within its service territory. This delivery service is regulated by the Maryland PSC.

BGE also provides customers with meter reading, billing, emergency response, regular maintenance, and balancing services.

Approximately 50% of the gas delivered on BGE's distribution system is for customers that purchase gas from alternative suppliers. These customers are charged fees to recover the costs BGE incurs to deliver the customers' gas through our distribution system.

For customers that buy their gas from BGE, there is a market-based rates incentive mechanism. Under market-based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers. BGE must secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period.

BGE purchases the natural gas it resells to customers directly from many producers and marketers. BGE has transportation and storage agreements that expire from 2005 to 2023.

BGE's current pipeline firm transportation entitlements to serve BGE's firm loads are 334,053 dekatherms (DTH) per day during the winter period and 309,053 DTH per day during the summer period.

BGE's current maximum storage entitlements are 235,080 DTH per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,092,977 DTH and a daily capacity of 311,500 DTH, and
- a propane air facility with a mined cavern with a total storage capacity equivalent to 564,200 DTH and a daily capacity of 85,000 DTH.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods.

BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas outside BGE's service territory. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance our supply of, and cost of, natural gas.

Gas Operating Statistics

	2004	**2003**	**2002**	**2001**	**2000**
Revenues *(In millions)*					
Residential					
Excluding Delivery Service	**$ 478.0**	$ 444.5	$ 342.1	$ 378.4	$ 328.4
Delivery Service Only	**14.2**	13.6	16.5	16.3	23.5
Commercial					
Excluding Delivery Service	**135.4**	128.6	89.4	115.5	97.9
Delivery Service Only	**28.0**	24.6	29.2	21.4	25.8
Industrial					
Excluding Delivery Service	**9.4**	11.5	9.3	12.8	10.9
Delivery Service Only	**7.8**	11.4	13.9	13.8	16.3
System Sales	**672.8**	634.2	500.4	558.2	502.8
Off-System Sales	**77.2**	84.8	74.8	113.6	101.0
Other	**7.0**	7.0	6.1	8.9	7.8
Total	**$ 757.0**	$ 726.0	$ 581.3	$ 680.7	$ 611.6
Distribution Volumes *(In thousands)* DTH					
Residential					
Excluding Delivery Service	**39,080**	40,894	35,364	33,147	34,561
Delivery Service Only	**6,053**	6,640	6,404	7,201	9,209
Commercial					
Excluding Delivery Service	**13,248**	13,895	11,583	12,334	13,186
Delivery Service Only	**34,120**	29,138	28,429	25,037	22,921
Industrial					
Excluding Delivery Service	**865**	1,143	1,207	1,386	1,386
Delivery Service Only	**14,310**	18,399	23,689	23,872	32,382
System Sales	**107,676**	110,109	106,676	102,977	113,645
Off-System Sales	**9,914**	12,859	18,551	20,012	22,456

	2004	2003	2002	2001	2000
Total	**117,590**	122,968	125,227	122,989	136,101
Customers *(In thousands)*					
Residential	**582.0**	575.2	567.3	558.7	553.7
Commercial	**41.6**	41.1	40.7	40.2	40.1
Industrial	**1.2**	1.2	1.3	1.4	1.4
Total	**624.8**	617.5	609.3	600.3	595.2

Operating statistics do not reflect the elimination of intercompany transactions.

"Delivery service only" refers to BGE's delivery of commodity to customers that was purchased by the customer from an alternate supplier.

Franchises

BGE has nonexclusive electric and gas franchises to use streets and other highways that are adequate and sufficient to permit them to engage in their present business. Conditions of the franchises are satisfactory.

Other Nonregulated Businesses

Energy Projects and Services

We offer energy projects and services designed primarily to provide energy solutions to large commercial and industrial and governmental customers. These energy products and services include:

- designing, constructing, and operating heating, cooling, and cogeneration facilities,
- energy consulting and power-quality services,
- services to enhance the reliability of individual electric supply systems, and
- customized financing alternatives.

Home Products and Gas Retail Marketing

We offer services to customers in Maryland including:

- home improvements,
- the service of heating, air conditioning, plumbing, electrical, and indoor air quality systems, and
- the sale of natural gas to residential customers.

Other

Our other nonregulated businesses include investments that we do not consider to be core operations. These include financial investments, real estate projects, and interests in a Panamanian distribution facility and in a fund that holds interests in two South American energy projects. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in losses. We discuss these non-core assets in more detail in *Item 7. Management's Discussion and Analysis Results of Operations* section.

Consolidated Capital Requirements

Our total capital requirements for 2004 were $762 million. Of this amount, $497 million was used in our nonregulated businesses and $265 million was used in our regulated business. We estimate our total capital requirements will be $915 million in 2005.

We continuously review and change our capital expenditure programs, so actual expenditures may vary from the estimate above. We discuss our capital requirements further in *Item 7. Management's Discussion and Analysis Capital Resources* section.

Environmental Matters

The development (involving site selection, environmental assessments, and permitting), construction, acquisition, and operation of electric generating and distribution facilities are subject to extensive federal, state, and local environmental and land use laws and regulations. From the beginning phases of development to the ongoing operation of existing or new electric generating and distribution facilities, our activities involve compliance with diverse laws and regulations that address emissions and impacts to air and water, protection of natural and cultural resources, and chemical and waste handling and disposal.

We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain on-going compliance. Our capital expenditures were approximately $235 million during the five-year period 2000-2004 to comply with existing environmental standards and regulations. Our estimated environmental capital requirements for the next three years are approximately $5 million in 2005, $45 million in 2006, and $80 million in 2007.

Air Quality

The Clean Air Act created the basic framework for the federal and state regulation of air pollution. The cornerstone of the Act is the requirement that National Ambient Air Quality Standards be established to protect public health and public welfare. In addition, the Act also includes technology-driven emission requirements. Many of these provisions could materially affect our facilities and are described in more detail below.

<u>National Ambient Air Quality Standards (NAAQS)</u>
The NAAQS are federal air quality standards that establish maximum ambient air concentrations for the following specific pollutants: ozone (smog), carbon monoxide, lead, particulates, sulfur dioxides (SO_2), and nitrogen dioxides (NO_2). Our generating facilities are primarily affected by ozone and particulates standards. Ozone is formed when sunlight interacts with emissions

of nitrogen oxides (NOx) and volatile organic compounds (such as from motor vehicle exhaust). Our generating facilities are subject to various permits and programs meant to achieve or preserve attainment of the standards for all these pollutants.

In order for states to achieve compliance with the NAAQS, federal and/or state legislation or regulation is likely to be adopted that will require additional emission reductions from our facilities. The Environmental Protection Agency (EPA) has proposed the Clean Air Interstate Rule (CAIR) to further reduce SO_2 and NOx emissions by addressing the interstate transport of $SO_2$and NOx emissions from fossil fuel-fired plants located primarily in the Eastern United States. In addition to CAIR, the Bush Administration is proposing a legislative approach (Clear Skies) which would require similar reductions in emissions of SO_2 and NOx. Depending on the timing and requirements of any federal proposal, one or more states in which we operate may impose more stringent or earlier emission reduction requirements. We favor the Clear Skies approach to achieve future emission reductions as the fairest and most expeditious manner in which to meet the NAAQS.

As a result of these regulatory and legislative proposals, along with new rules to impose limits on hazardous substances, we expect more stringent air emission standards to be adopted. If new requirements are promulgated as expected we will install additional air emission control equipment at our coal-fired generating facilities in Maryland and at our co-owned coal-fired facilities in Pennsylvania to meet air quality standards. We include in our estimated environmental capital requirements capital spending for these projects, which we expect will be approximately $2 million in 2005, $32 million in 2006, and $75 million in 2007. If these rules are promulgated as we have assumed in our projections, we will spend another $400-$500 million of capital from 2008-2010. Our estimates are subject to significant uncertainties including the timing of any regulatory or legislative change, its implementation timetable, and the amount of emissions reductions that will be required. As a result, we cannot predict our capital spending or the scope or timing of these projects with certainty, and the actual expenditures, scope and timing could differ significantly from our estimates.

On March 10, 2005, the EPA adopted CAIR. We are in the process of evaluating the impact of the rules on our financial results.

We own several generating facilities in Maryland and California, states that do not meet the NAAQS for ozone. The Clean Air Act requires states to assess fees against every major stationary source of NOx and volatile organic compounds in areas that have not met the NAAQS for ozone if the NAAQS is not achieved by a specified deadline. If implemented, the fees would be assessed based on the magnitude of a source's emissions as compared to its emissions when the area failed to meet the deadline. The exact method of computing these fees has not been established and will depend in part on state implementation regulations that have not been finalized.

There are various deadlines for Maryland and California to meet the NAAQS for ozone with the earliest being November 2005. Assessment of fees would commence in 2006 if the current effective dates are maintained. However, there is significant uncertainty regarding the date when fees would be assessed and whether they would be applicable to our facilities because the EPA is involved in litigation regarding these issues. Consequently, we are unable to estimate the ultimate applicability, timing or financial impact of the fees in light of the uncertainty surrounding the effective dates and the methodology that will be used in calculating the fees.

Hazardous Air Emissions
The Clean Air Act requires the EPA to evaluate the public health impacts of hazardous air emissions from electric steam generating facilities. In December 2003, the EPA proposed to regulate the emissions of mercury from coal-fired facilities and nickel from residual oil-fired facilities. Under the mercury proposal, the EPA has proposed compliance alternatives, including a unit specific standard and a cap and trade program. As proposed, compliance with the unit specific limits would be required as early as March 2008, but could be delayed for at least one year as allowed under the proposed requirements. Compliance with the mercury cap and trade program would be required by January 2010. The Bush Administration's Clear Skies legislative proposal also addresses regulation of mercury through a cap and trade approach. The nickel emission limits for residual oil-fired facilities would require compliance by March 2008 but could be delayed for at least one year as allowed under the proposed requirements. We believe final regulations could be issued in 2005 and could affect all coal and oil-fired boilers at our generating facilities. The cost of compliance with the final regulations could be material.

New Source Review
The EPA and several states filed lawsuits against a number of coal-fired power plants primarily 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 located in Maryland. The EPA also sent similar, but narrower, information requests to two of our newer Pennsylvania waste-coal burning plants in which we have an ownership interest. We have responded to the EPA, and

as of the date of this report the EPA has taken no further action.

Based on the level 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.

In August 2003, the EPA's equipment replacement rule was promulgated. The rule establishes an equipment replacement cost threshold for determining when major new source review requirements are triggered. The rule provides that plant owners may spend up to 20% of the replacement value of a generation unit on certain component replacements each year without triggering requirements for new pollution controls. A legal challenge to this rule was filed with the United States Court of Appeals and a stay was issued which delayed its effective date. The EPA has also determined to seek additional comment on certain features of the rule, including the 20% threshold. We cannot predict the timing or outcome of the legal challenge or the EPA comment process, or their possible effect on our financial results.

Global Climate Change

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.

Water Quality

The Clean Water Act established the basic framework for federal and state regulation of water pollution control. The Act requires facilities that discharge waste or storm water into the waters of the United States to obtain permits requiring them to meet effluent limits in order to achieve ambient water quality standards in the receiving waters. Under current provisions of the Clean Water Act, existing discharge permits are renewed every five years, at which time permit effluent limits come under extensive review and can be modified to account for more stringent regulations. In addition, the permits can be modified at any time.

Water Intake Regulations

In July 2004, the EPA published final rules under the Clean Water Act that require cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. The final rules require the installation of additional intake screens or other protective measures, as well as extensive site-specific study and monitoring requirements. We currently have six facilities affected by the regulation. The rule allows for a number of compliance options that will be assessed through 2007, following which we will determine whether any action is required and what our most viable options are if any action is required. Until we determine our most viable option under the final rules, we cannot estimate our compliance costs. However, the costs associated with the final rules could be material.

Hazardous and Solid Waste

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) established the basic framework for federal and state regulations that can require any individual or entity that may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to such site, to share in remediation costs. Except to the extent discussed in *Note 12 to the Consolidated Financial Statements*, compliance with CERCLA requirements is not expected to have a material adverse effect on our financial results.

The Resource Conservation and Recovery Act (RCRA) gives the EPA authority to control hazardous waste from "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also sets forth a framework for the management of non-hazardous wastes. Although RCRA focuses only on active and future facilities and, unlike CERCLA, does not address abandoned or historical sites, there are provisions that require phasing-out land disposal of hazardous waste, more stringent hazardous waste management standards, and a comprehensive underground storage tank program.

Our coal-fired generating facilities produce approximately two million tons of combustion by-products ("ash") each year, including approximately 700,000 tons at our Maryland plants. Of the two million tons, approximately half is beneficially re-used in various projects, including as structural fill in surface mine reclamation, and half is placed in landfills. In 2000, the EPA decided not to regulate combustion ash as a hazardous waste under RCRA. Instead, the EPA announced its intention to develop national standards, currently scheduled to be proposed in April 2006, to regulate this material as a non-hazardous waste, and is developing regulations governing the placement of ash in landfills, surface impoundments, and sand/gravel surface mines. The EPA is also developing regulations for ash placement in coal mines, which are expected to be proposed in October 2007. Federal regulation has the potential to result in additional requirements such as groundwater monitoring, liners, and leachate

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collection and treatment systems for all landfills, surface impoundments, and sand and gravel mines used for ash management. Depending on the scope of any final requirements, our compliance costs could be material.

As a result of these regulatory proposals, the remaining ash placement capacity at our current mine reclamation site and our current ash generation projections, we are exploring our options for the placement of ash, including construction of an ash placement facility. Over the next five years, we estimate that our capital expenditures for this project will be as follows: approximately $10 million in 2006 and, if we decide to construct a facility, approximately $55 million in 2008 towards the purchase of land. Our estimates are subject to significant uncertainties including the timing of any regulatory change, its implementation timetable, and the scope of the final requirements. As a result, we cannot predict our capital spending or the scope and timing of this project with certainty, and the actual expenditures, scope and timing could differ significantly from our estimates.

Employees

Constellation Energy and its subsidiaries had approximately 9,570 employees at December 31, 2004. At the Nine Mile Point plant, approximately 700 employees are represented by the International Brotherhood of Electrical Workers, Local 97. The labor contract with this union expires in June 2006. We believe that our relationship with this union is satisfactory, but there can be no assurances that this will continue to be the case.

Item 2. Properties

Constellation Energy's corporate offices occupy approximately 106,000 square feet of leased office space in Baltimore, Maryland. The corporate offices for most of our merchant energy business occupy approximately 172,000 square feet of leased office space in another building in Baltimore, Maryland. We describe our electric generation properties on the next page. We also have leases for other offices and services located in the Baltimore metropolitan region, and for various real property and facilities relating to our generation projects.

BGE's principal headquarters building is located in downtown Baltimore. In January 2004, BGE sold a portion of its headquarters building and is in the process of consolidating its operations into the remainder of the building. In addition, BGE owns propane air and liquefied natural gas facilities as discussed in *Item 1. Business Gas Business* section.

BGE also has rights-of-way to maintain 26-inch natural gas mains across certain Baltimore City-owned property (principally parks) which expired in 2004. BGE is in the process of renewing the rights-of-way with Baltimore City for an additional 25 years. The expiration of the rights-of-way does not affect BGE's ability to use the rights-of-way during the renewal process.

BGE has electric transmission and electric and gas distribution lines located:

- in public streets and highways pursuant to franchises, and
- on rights-of-way secured for the most part by grants from owners of the property.

All of BGE's property is subject to the lien of BGE's mortgage securing its mortgage bonds. All of the generation facilities transferred to affiliates by BGE on July 1, 2000, along with the stock we own in certain of our subsidiaries, are subject to the lien of BGE's mortgage.

We believe we have satisfactory title to our power project facilities in accordance with standards generally accepted in the energy industry, subject to exceptions, which in our opinion, would not have a material adverse effect on the use or value of the facilities.

We also lease office space throughout North America, in the United Kingdom, and in Australia to support our merchant energy business.

The following table describes our generating facilities:

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
			(at December 31, 2004)		
Mid-Atlantic Region					
Calvert Cliffs	Calvert Co., MD	1,735	100.0	1,735	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,286	100.0	1,286	Coal
H. A. Wagner	Anne Arundel Co., MD	1,009	100.0	1,009	Coal/Oil/Gas
C. P. Crane	Baltimore Co., MD	399	100.0	399	Oil/Coal
Keystone	Armstrong and Indiana Cos., PA	1,711	21.0	359 (A)	Coal
Conemaugh	Indiana Co., PA	1,711	10.6	181 (A)	Coal
Perryman	Harford Co., MD	360	100.0	360	Oil/Gas
Riverside	Baltimore Co., MD	249	100.0	249	Oil/Gas
Handsome Lake	Rockland Twp, PA	250	100.0	250	Gas
Notch Cliff	Baltimore Co., MD	128	100.0	128	Gas
Westport	Baltimore City, MD	121	100.0	121	Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor	Safe Harbor, PA	416	66.7	277	Hydro
Total Mid-Atlantic Region		9,439		6,418	
Plants with Power Purchase Agreements					
High Desert	Victorville, CA	830	100.0	830	Gas
Nine Mile Point Unit 1	Scriba, NY	609	100.0	609	Nuclear
Nine Mile Point Unit 2	Scriba, NY	1,148	82.0	941	Nuclear
R.E. Ginna	Ontario, NY	495	100.0	495	Nuclear
Oleander	Brevard Co., FL	680	100.0	680	Oil/Gas
University Park	Chicago, IL	300	100.0	300	Gas
Total Plants with Power Purchase Agreements		4,062		3,855	
Competitive Supply					
Rio Nogales	Seguin, TX	800	100.0	800	Gas
Holland Energy	Shelby Co., IL	665	100.0	665	Gas
Big Sandy	Neal, WV	300	100.0	300	Gas
Wolf Hills	Bristol, VA	250	100.0	250	Gas
Total Competitive Supply		2,015		2,015	
Other					
Panther Creek	Nesquehoning, PA	83	50.0	42	Waste Coal
Colver	Colver Township, PA	110	25.0	28	Waste Coal
Sunnyside	Sunnyside, UT	53	50.0	26	Waste Coal
ACE	Trona, CA	102	31.1	31	Coal
Jasmin	Kern Co., CA	33	50.0	17	Coal
POSO	Kern Co., CA	33	50.0	17	Coal
Mammoth Lakes G-1	Mammoth Lakes, CA	8	50.0	4	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	12	50.0	6	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	12	50.0	6	Geothermal
Soda Lake I	Fallon, NV	3	50.0	2	Geothermal
Soda Lake II	Fallon, NV	13	50.0	7	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	Biomass
Fresno	Fresno, CA	24	50.0	12	Biomass
Chinese Station	Sonora, CA	22	45.0	10	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
SEGS IV	Kramer Junction, CA	30	12.0	4	Solar
SEGS V	Kramer Junction, CA	30	4.0	1	Solar
SEGS VI	Kramer Junction, CA	30	9.0	3	Solar
Total Other		654		244	

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
Total Generating Facilities		16,170		12,532	

(A) Reflects our proportionate interest in and entitlement to capacity from Keystone and Conemaugh, which include 2 megawatts of diesel capacity for Keystone and 1 megawatt of diesel capacity for Conemaugh.

The following table describes our processing facilities:

Plant	Location	% Owned	Primary Fuel
A/C Fuels	Hazelton, PA	50.0	Coal Processing
Gary PCI	Gary, IN	24.5	Coal Processing
Low Country	Cross, SC	99.0	Synfuel Processing
PC Synfuel VA I	Appalachia, VA	16.7	Synfuel Processing
PC Synfuel WV I	Charleston, WV	16.7	Synfuel Processing
PC Synfuel WV II	Mount Storm, WV	16.7	Synfuel Processing
PC Synfuel WV III	Mayberry, WV	16.7	Synfuel Processing

Item 3. Legal Proceedings

We discuss our legal proceedings in *Note 12 to Consolidated Financial Statements.*

Item 4. Submission of Matters to Vote of Security Holders

Not applicable.

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	50	Chairman of the Board of Constellation Energy (since July 2002), President and Chief Executive Officer of Constellation Energy (since November 2001); and Chairman of the Board of BGE (since July 2002)	Global Head of Investment Banking and Global Head of Private Banking Deutsche Banc Alex. Brown; and Vice Chairman Bankers Trust Corporation.
E. Follin Smith	45	Executive Vice President (since January 2004) and Chief Financial Officer (since June 2001) and Chief Administrative Officer (since December 2003) of Constellation Energy and Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company (since January 2002)	Senior Vice President Constellation Energy; Senior Vice President and Chief Financial Officer Armstrong Holdings, Inc.; Vice President and Treasurer Armstrong Holdings, Inc. (filed for bankruptcy under Chapter 11 on December 6, 2000); and Chief Financial Officer General Motors Delphi Chassis Systems.
Thomas V. Brooks	42	President of Constellation Energy Commodities Group, Inc. (formerly Constellation Power Source, Inc.) (since October 2001); Executive Vice President of Constellation Energy (since January 2004)	Vice President of Business Development and Strategy Constellation Energy; and Vice President Goldman Sachs.
Michael J. Wallace	57	President of Constellation Generation Group, LLC (since January 2002); Executive Vice President of Constellation Energy (since January 2004)	Managing Director and Member Barrington Energy Partners; and Senior Vice President Commonwealth Edison.
Thomas F. Brady	55	Executive Vice President, Corporate Strategy and Retail Competitive Supply of Constellation Energy (since January 2004)	Senior Vice President, Corporate Strategy and Development Constellation Energy; Vice President, Corporate Strategy and Development Constellation Energy; and Vice President, Corporate Strategy and

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
			Development BGE.

Kenneth W. DeFontes, Jr.	54	President and Chief Executive Officer of Baltimore Gas and Electric Company and Senior Vice President of Constellation Energy (since October 2004)	Vice President, Electric Transmission and Distribution BGE; and Manager, Corporate Strategy and Development Constellation Energy.
Paul J. Allen	53	Senior Vice President, Corporate Affairs of Constellation Energy (since January 2004)	Vice President, Corporate Affairs Constellation Energy; and Senior Vice President and Group Head Ogilvy Public Relations.
John R. Collins	47	Senior Vice President (since January 2004) and Chief Risk Officer of Constellation Energy (since December 2001)	Vice President Constellation Energy; Managing Director Finance Constellation Power Source Holdings, Inc.; and Senior Financial Officer Constellation Power Source, Inc.
Beth S. Perlman	44	Senior Vice President (since January 2004) and Chief Information Officer of Constellation Energy (since April 2002)	Vice President, Technology Enron Corporation.
Marc L. Ugol	46	Senior Vice President, Human Resources of Constellation Energy (since January 2004)	Vice President, Human Resources Constellation Energy; Senior Vice President, Human Resources and Administration Tellabs, Inc.; and Senior Vice President, Human Resources Platinum Technology International.

Officers are elected by, and hold office at the will of, the Board of Directors and do not serve a "term of office" as such. There is no arrangement or understanding between any director or officer and any other person pursuant to which the director or officer was selected.

PART II

Item 5. Market for Registrant's Common Equity and Related Shareholder Matters

Stock Trading

Constellation Energy's common stock is traded under the ticker symbol CEG. It is listed on the New York, Chicago, and Pacific stock exchanges. It has unlisted trading privileges on the Boston, Cincinnati, and Philadelphia exchanges.

As of February 28, 2005, there were 45,843 common shareholders of record.

Dividend Policy

Constellation Energy pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on Constellation Energy paying common stock dividends.

Dividends have been paid continuously since 1910 on the common stock of Constellation Energy, BGE, and their predecessors. Future dividends depend upon future earnings, our financial condition, and other factors.

In January 2005, we announced an increase in our quarterly dividend from $0.285 to $0.335 per share on our common stock payable April 1, 2005 to holders of record on March 10, 2005. This is equivalent to an annual rate of $1.34 per share.

Quarterly dividends were declared on our common stock during 2004 and 2003 in the amounts set forth below.

BGE pays dividends on its common stock after its Board of Directors declares them. There are no contractual limitations on BGE paying common stock dividends unless:

BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or

any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Common Stock Dividends and Price Ranges

	2004			2003		
		Price*			Price*	
	Dividend Declared	High	Low	Dividend Declared	High	Low
First Quarter	$ 0.285	$ 41.47	$ 38.52	$ 0.260	$ 30.23	$ 25.17
Second Quarter	0.285	41.35	35.89	0.260	34.92	27.50
Third Quarter	0.285	41.18	36.76	0.260	37.65	31.75
Fourth Quarter	0.285	44.90	39.90	0.260	39.61	35.03
Total	$ 1.140			$ 1.040		

* Based on New York Stock Exchange Composite Transactions.

Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2004	2003	2002	2001	2000
			(In millions, except per share amounts)		
Summary of Operations					
Total Revenues	**$ 12,549.7**	$ 9,687.8	$ 4,718.6	$ 3,877.3	$ 3,772.5
Total Expenses	**11,471.3**	8,647.7	3,893.7	3,525.7	3,008.0
Net (Loss) Gain on Sales of Investments and Other Assets	**(1.2)**	26.2	261.3	6.2	78.1
Income From Operations	**1,077.2**	1,066.3	1,086.2	357.8	842.6
Other Income	**14.1**	19.1	30.5	1.3	4.2
Fixed Charges	**330.3**	340.2	281.5	238.8	271.4
Income Before Income Taxes	**761.0**	745.2	835.2	120.3	575.4
Income Taxes	**172.2**	269.5	309.6	37.9	230.1
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**588.8**	475.7	525.6	82.4	345.3
Loss from Discontinued Operations, Net of Income Taxes	**(49.1)**				
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes		(198.4)		8.5	
Net Income	**$ 539.7**	$ 277.3	$ 525.6	$ 90.9	$ 345.3
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Assuming Dilution	**$ 3.40**	$ 2.85	$ 3.20	$ 0.52	$ 2.30
Loss from Discontinued Operations	**(0.28)**				
Cumulative Effects of Changes in Accounting Principles		(1.19)		0.05	
Earnings Per Common Share Assuming Dilution	**$ 3.12**	$ 1.66	$ 3.20	$ 0.57	$ 2.30
Dividends Declared Per Common Share	**$ 1.14**	$ 1.04	$ 0.96	$ 0.48	$ 1.68
Summary of Financial Condition					
Total Assets	**$ 17,347.1**	$ 15,593.0	$ 14,943.3	$ 14,697.5	$ 13,248.1
Short-Term Borrowings	**$**	$ 9.6	$ 10.5	$ 975.0	$ 243.6
Current Portion of Long-Term Debt	**$ 480.4**	$ 343.2	$ 426.2	$ 1,406.7	$ 906.6
Capitalization					

	2004	2003	2002	2001	2000
Long-Term Debt	**$ 4,813.2**	$ 5,039.2	$ 4,613.9	$ 2,712.5	$ 3,159.3
Minority Interests	**90.9**	113.4	105.3	101.7	97.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**4,726.9**	4,140.5	3,862.3	3,843.6	3,174.0
Total Capitalization	**$ 9,821.0**	$ 9,483.1	$ 8,771.5	$ 6,847.8	$ 6,621.0
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**3.11**	2.98	3.33	1.18	2.78
Book Value Per Share of Common Stock	**$ 26.81**	$ 24.68	$ 23.44	$ 23.48	$ 21.09

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

We discuss items that affect comparability between years, including acquisitions, accounting changes, including the impact of adopting Emerging Issues Task Force Issue (EITF) 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*, and special items, in *Item 7. Management's Discussion and Analysis*.

Baltimore Gas and Electric Company and Subsidiaries

	2004	2003	2002	2001	2000
			(In millions)		
Summary of Operations					
Total Revenues	**$ 2,724.7**	$ 2,647.6	$ 2,547.3	$ 2,720.7	$ 2,746.8
Total Expenses	**2,353.3**	2,262.6	2,181.0	2,408.9	2,334.4
Income From Operations	**371.4**	385.0	366.3	311.8	412.4
Other (Expense) Income	**(6.4)**	(5.4)	10.7	0.4	7.5
Fixed Charges	**96.2**	111.2	140.6	154.6	184.0
Income Before Income Taxes	**268.8**	268.4	236.4	157.6	235.9
Income Taxes	**102.5**	105.2	93.3	60.3	92.4
Net Income	**166.3**	163.2	143.1	97.3	143.5
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Earnings Applicable to Common Stock	**$ 153.1**	$ 150.0	$ 129.9	$ 84.1	$ 130.3
Summary of Financial Condition					
Total Assets	**$ 4,662.9**	$ 4,706.6	$ 4,779.9	$ 4,954.5	$ 4,657.4
Short-Term Borrowings	**$**	$	$	$	$ 32.1
Current Portion of Long-Term Debt	**$ 165.9**	$ 330.6	$ 420.7	$ 666.3	$ 567.6
Capitalization					
Long-Term Debt	**$ 1,359.5**	$ 1,343.7	$ 1,499.1	$ 1,821.7	$ 1,864.4
Minority Interest	**18.7**	18.9	19.4	5.0	4.6
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,566.0**	1,487.7	1,461.7	1,131.4	802.3
Total Capitalization	**$ 3,134.2**	$ 3,040.3	$ 3,170.2	$ 3,148.1	$ 2,861.3
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**3.75**	3.36	2.66	1.99	2.27
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**3.08**	2.82	2.31	1.75	2.03

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is a North American energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in *Note 3*.

This report is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. References in this report to the "regulated business(es)" are to BGE. We discuss our business in more detail in *Item 1. Business* section.

In this discussion and analysis, we will 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, which present the results of our operations for 2004, 2003, and 2002. Our results reflect a significant increase in revenues and in purchased fuel and energy expenses mainly due to the implementation of Emerging Issues Task Force Issue (EITF) 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* in January 2003, as well as the full year impact of our 2002 acquisitions. We discuss our acquisitions in more detail in *Note 15*. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income.

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- We then describe the business environment in which we operate including how regulation, weather, and other factors affect our business.
- Next, we discuss our critical accounting policies. These are the accounting policies that are most important to both the portrayal of our financial condition and results of operations and require management's most difficult, subjective or complex judgment.
- We highlight significant events that are important to understanding our results of operations and financial condition.
- We then review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.
- We review our financial condition addressing our sources and uses of cash, security ratings, capital resources, capital requirements, commitments, and off-balance sheet arrangements.

We conclude with a discussion of our exposure to various market risks.

Strategy

We are pursuing a strategy of distributing energy and energy related services through our competitive supply activities and BGE, our regulated utility located in Maryland. Our merchant energy business focuses on short-term and long-term, high-value sales of energy, capacity, and related products to various customers, including distribution utilities, municipalities, cooperatives, industrial customers, and commercial customers primarily in the regional markets in which end-use customer electricity and gas rates have been deregulated and thereby separated from the cost of generation and gas supply. These markets include:

- the Northeast (New England and New York),
- the Mid-Atlantic and Midwest regions,
- the West region (Texas and California), and
- certain areas in Canada.

We obtain this energy through both owned and contracted supply resources. Our generation fleet is strategically located in deregulated markets across the country and is diversified by fuel type, including nuclear, coal, gas, oil, and renewable sources. Where we do not own generation, we contract for power from other merchant providers, typically through power purchase agreements. We intend to remain diversified between regulated transmission and distribution and competitive supply. We will use both our owned generation and our contracted generation to support our competitive supply operations.

We are a leading national competitive supplier of energy in the deregulated markets previously discussed. In our wholesale and commercial and industrial retail marketing activities we are leveraging our recognized expertise in providing full requirements energy and energy related services to enter markets, capture market share, and organically grow these businesses. Through the application of technology, intellectual capital, process improvement, and increased scale, we are seeking to reduce the cost of delivering full requirements energy and energy related services and managing risk.

We are also responding proactively to customer needs by expanding the variety of products we offer. Our wholesale competitive supply activities include a growing customer products operation that markets physical energy products and risk management and logistics services to generators, distributors, producers of coal, natural gas and fuel oil, and other consumers.

Within our retail competitive supply activities, we are marketing a broader array of products and expanding our markets. Over time, we may consider integrating the sale of electricity and natural gas to provide one energy procurement solution for our customers.

Collectively, the integration of owned and contracted electric generation assets with origination, fuel procurement, and risk management expertise, allows our merchant energy business to earn incremental margin and more effectively manage energy and commodity price risk over geographic regions and over time. Our focus is on providing solutions to customers' energy needs, and our wholesale marketing and risk management operation adds value to our owned and contracted 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 wholesale marketing 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 wholesale marketing and risk management operation with generation assets that have diversified geographic, fuel, and dispatch characteristics. We also expect to grow organically through selling a greater number of physical energy products and services to large energy customers. We expect to achieve operating efficiencies within our competitive supply operation and our generation fleet by selling more products through our existing sales force, benefiting from efficiencies of scale, adding to the capacity of existing plants, and making our business processes more efficient.

We expect BGE and our other retail energy service businesses to grow through focused and disciplined expansion primarily from new customers. At BGE, we are also focused on enhancing reliability and customer satisfaction.

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 the business environment and regulatory changes, and to maintain a strong balance sheet and investment-grade credit quality.

We are constantly reevaluating our strategies and might consider:

- acquiring or developing additional generating facilities to support our merchant energy business,
- mergers or acquisitions of utility or non-utility businesses or assets, and
- sale of assets or one or more businesses.

Business Environment

General Industry

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

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

Over the last few years, the energy markets have been highly volatile with significant changes in natural gas and power prices, as well as the continuation of reduced liquidity in the marketplace. We continue to actively manage our credit portfolio to attempt to reduce the impact of a potential counterparty default. We discuss our customer (counterparty) credit and other risks in more detail in the *Market Risk* section.

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

Electric Competition

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

Various states have moved to restructure their electricity markets. The pace of deregulation in these states varies based on historical moves to competition and responses to recent market events. While many states continue their support for retail competition and industry restructuring, other states that were considering deregulation have slowed their plans or postponed consideration. In addition, other states are reconsidering deregulation. We discuss merchant competition in more detail in *Item 1. Business Competition* section.

The impacts of electric deregulation on BGE in Maryland are discussed in *Item 1. Business Electric Regulatory Matters and Competition* section.

Gas Competition

The wholesale price of natural gas is not subject to regulation. All BGE gas customers have the option to purchase gas from alternate suppliers.

Regulation by the Maryland PSC

In addition to electric restructuring which was discussed in *Item 1. Business Electric Regulatory Matters and Competition* section, regulation by the Maryland Public Service Commission (Maryland PSC) significantly 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 the Federal Energy Regulatory Commission (FERC). BGE's electric rates are unbundled in customer billings to show separate components for delivery service (i.e. base rates), competitive transition charges, electric supply (commodity charge), transmission, a universal service surcharge, and certain taxes. The rates for BGE's regulated gas business continue to consist of a delivery charge (base rate) and a commodity charge.

Base Rates

The base rate is the rate the Maryland PSC allows BGE to charge its customers for the cost of providing them delivery 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 its utility plant investment and operating costs, plus a profit, beginning at the time of replacement. Generally, rate increases improve the earnings of our regulated business 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 July 2006. Electric base rates were frozen until July 2004 for commercial and industrial customers. We discuss electric deregulation in *Item 1. Business Electric Regulatory Matters and Competition* section.

Electric Commodity and Transmission Charges

BGE electric commodity and transmission charges (standard offer service) are discussed in *Item 1. Business Electric Regulatory Matters and Competition* section.

Gas Commodity Charge

BGE charges its gas customers separately for the natural gas they purchase. The price BGE charges 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 proceeding with the Maryland PSC in more detail in the *Regulated Gas Business Gas Cost Adjustments* section and in *Note 6*.

Federal Regulation

FERC

The FERC has jurisdiction over various aspects of our business, including transmission and wholesale electricity sales. Although a FERC proposed rulemaking regarding implementation of a standard market design for wholesale electric markets appears to have halted, FERC has indicated that it continues to have a strong commitment to customer-focused, competitive wholesale power markets, with appropriate flexibility to accommodate regional differences. We believe that FERC's commitment should result in improved competitive markets across various regions.

Since 1997, operation of BGE's transmission system has been under the authority of PJM, the Regional Transmission Organization (RTO) for the Mid-Atlantic region, pursuant to FERC oversight. As the transmission operator, PJM operates the energy markets and conducts day-to-day operations of the bulk power system.

In addition to PJM, RTOs exist in other regions of the country, such as the Midwest, New York, and New England. In addition to operation of the transmission system and responsibility for transmission system reliability, these RTOs also operate, or plan to operate, energy markets for their region pursuant to FERC's oversight. Our merchant energy business participates in these regional energy markets. These markets are continuing to develop, and revisions to market structure are subject to review and approval in proceedings before FERC and other regulatory bodies. We cannot predict the outcome of these proceedings at this time. However, changes to the structure of these markets could have a material effect on our financial results.

Recent initiatives at FERC have included a review of its methodology for the granting of market-based rate authority to sellers of electricity. FERC has announced new interim tests that will be used to determine the extent to which companies may have market power in certain regions. Where market power is found to exist, companies may be required by FERC to implement measures to mitigate the market power in order to maintain market-based rate authority. In addition, FERC is reviewing other aspects of its granting of market-based rate authority, including transmission market power, affiliate abuse, and barriers to entry. We cannot determine the eventual outcome of FERC's efforts in this regard and their impact on our financial results at this time.

In January 2005, BGE and other transmission owners filed a joint application at FERC to have network transmission rates established through a formula that tracks costs instead of through fixed rates in accordance with FERC guidelines. If accepted by FERC, the formula approach would take effect in June 2005, and transmission rates would be adjusted in June of each year based on the formula without the need for another transmission rate filing. We cannot predict the outcome of this proceeding including whether the FERC will accept the formula approach.

Other market changes are also being considered, including potential revisions to PJM's capacity market and rate design. Such changes will be subject to FERC's review and approval. We cannot predict the outcome of these proceedings or the possible effect on our, or BGE's, financial results at this time.

Federal Energy Legislation

While energy legislation was not passed by Congress in 2004, we expect that some form of energy legislation will be brought before Congress during the upcoming legislative session. We cannot predict the impact of potential legislation on our financial results at this time.

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. Changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market, which may affect our results in any given period. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. 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, thus we are not typically exposed to the effects of extreme weather in all parts of our business at once.

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. Weather affects residential sales more than commercial and industrial sales, which are mostly affected by business needs for electricity and gas. The Maryland PSC allows BGE 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 *Regulated Gas Business Weather Normalization* section.

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 and transmission availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- implementation of new market rules governing operations of regional power pools,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions,
- changes in the nature and extent of federal and state regulations, and
- international demand.

These 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,
- local transportation systems, and
- the nature and extent of electricity deregulation.

Our merchant energy business contracts with rail companies to ensure the delivery of coal to our coal-fired generation facilities. The timely delivery of coal together with the maintenance of appropriate levels of inventory is necessary to allow for continued, reliable generation from these facilities. In the second, third, and fourth quarters of 2004, we experienced delays in deliveries from one of the rail companies that supplies coal to our generating facilities. In response, we procured coal using an alternative delivery method to meet our contractual load obligations. We discuss the impact of these delays on our financial results in the *Mid-Atlantic Region* section. We expect the majority of the coal that was not delivered during 2004 will be delivered during 2005.

Other factors 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 downturn, our customers tend to consume less electricity and gas.

Environmental Matters and Legal Proceedings

We discuss details of our environmental matters in *Note 12* and *Item 1. Business Environmental Matters* section. We discuss details of our legal proceedings in *Note 12*. Some of this information is about costs that may be material to our financial results.

Accounting Standards Adopted and Issued

We discuss recently adopted and issued accounting standards in *Note 1*.

Critical Accounting Policies

Our discussion and analysis of financial condition and results of operations is 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 revenues and expenses in our Consolidated Statements of Income,
- our reported amounts of assets and liabilities in our Consolidated Balance Sheets, and
- our disclosure of contingent assets and liabilities.

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

Management believes the following accounting policies represent critical accounting policies as defined by the Securities and Exchange Commission (SEC). The SEC defines critical accounting policies as those that are both most important to the portrayal of a company's financial condition and results of operations 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. 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*.

Revenue Recognition/Mark-to-Market Method of Accounting

Our merchant energy business enters into contracts for energy, other energy-related commodities, and related derivatives. 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 (including hedge accounting) in more detail in *Note 1*.

We record revenues using the mark-to-market method of accounting for derivative 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 these derivatives as mark-to-market energy assets and liabilities at the time of contract execution. We record the changes in mark-to-market energy assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income.

Mark-to-market energy assets and liabilities consist of a combination of energy and energy-related derivative contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices, contract quantities, or both. The market prices and quantities used to determine fair value reflect management's best estimate considering various factors. However, future market prices and actual quantities will vary from those used in recording mark-to-market energy assets and liabilities, and it is possible that such variations could be material.

We record valuation adjustments to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market energy assets and liabilities. The effect of these uncertainties is 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 uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

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

Close-out adjustment represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This valuation adjustment has the effect of valuing "long" positions (the purchase of a commodity) at the bid price and "short" positions (the sale of a commodity) at the offer price. We compute this adjustment using a market-based estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. The level of total close-out valuation adjustments 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. To the extent that we are not able to obtain observable market information for similar contracts, the close-out adjustment is equivalent to the initial contract margin, thereby resulting in no gain or loss at inception. In the absence of observable market information, there is a presumption that the transaction price is equal to the market value of the contract, and therefore we do not recognize a gain or loss at inception. We recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.

Credit-spread adjustment for risk management purposes, we compute the value of our mark-to-market energy 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 energy assets to reflect the credit-worthiness of each counterparty based upon either published credit ratings, or equivalent internal credit ratings and associated default probability percentages. We compute this adjustment by applying a default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this adjustment 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, and changes in market prices 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.

In October 2002, the EITF reached a consensus on Issue 02-3. This consensus prohibits mark-to-market accounting for energy-related contracts that do not meet the definition of a derivative under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*. As a result, we began to account for all non-derivative contracts on the accrual basis of accounting effective January 1, 2003 as described in *Note 1*. The consensus also prohibits recording 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, and it 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.

EITF 02-3 affects the timing of recognizing earnings on non-derivative transactions. In general, beginning in 2003 earnings on non-derivative 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 are the same as they would have been under mark-to-market accounting, our reported earnings for contracts subject to EITF 02-3 generally match the cash flows from those contracts more closely. Additionally, because we record revenues and costs on a gross basis under accrual accounting, our revenues and costs increased, but our earnings have not been affected by gross versus net reporting.

The impact of derivative contracts on our revenues and costs is affected by many factors, including:

- our ability to designate and qualify derivative contracts for normal purchase and sale accounting or hedge accounting under SFAS No. 133,
- potential volatility in earnings from derivative contracts that serve as economic hedges but do not meet the accounting requirements to qualify for normal purchase and sale accounting or hedge accounting,
- our ability to enter into new mark-to-market derivative origination transactions, and
- sufficient liquidity and transparency in the energy markets to permit us to record gains at inception of new derivative contracts because fair value is evidenced by quoted market prices, current market transactions, or other observable market information.

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

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

Long-Lived Assets

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 requirements 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 are:

- 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 provides 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 requires us to estimate uncertain future cash flows.

In order to estimate an asset's future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. 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 estimate 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 held for sale under SFAS No. 144, an impairment loss is recognized to the extent their carrying amount exceeds their fair value less costs to sell.

If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment loss. The estimation of fair value under SFAS No. 144, whether in conjunction with an asset to be held and used or with an asset held for sale, also involves 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. 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 requirements for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

The evaluation and measurement of impairments under the APB No. 18 standard involves the same uncertainties as described on the previous page 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.

Debt and Equity Securities

Our investments in debt and equity securities are subject to impairment evaluations under SFAS No. 115, A*ccounting for Certain Investments in Debt and Equity Securities.* SFAS No. 115 requires us to determine whether a decline in fair value of an investment below the amortized cost basis is other than temporary. If we determine that the decline in fair value is judged to be other than temporary, the cost basis of the investment must be written down to fair value as a new cost basis. We discuss EITF 03-1, *The Meaning of Other Than Temporary Impairment and Its Application to Certain Investments,* in the *Accounting Standards Issued* section of *Note 1*.

Goodwill

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We account for goodwill and other intangibles under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. We do not amortize goodwill and certain other intangible assets. SFAS No. 142 requires us to evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using techniques similar to those used to estimate future cash flows for long-lived assets as discussed on the previous page, which involves judgment. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value.

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.

Our nuclear decommissioning costs represent our largest asset retirement obligation. This obligation primarily results from the requirement to decommission and decontaminate our nuclear generating facilities in connection with their future retirement. We utilize site-specific decommissioning cost estimates to determine our nuclear asset retirement obligations. However, given the magnitude of the amounts involved, complicated and ever-changing technical and 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.

Significant Events

In 2004, we recorded the following special items in earnings:

	Pre-Tax	After-Tax
	(In millions)	

	Pre-Tax	After-Tax
Loss from discontinued operations	$ (75.6)	$ (49.1)
Recognition of 2003 synthetic fuel tax credits		35.9
Workforce reduction costs	(9.7)	(5.9)
Impairment losses and other costs	(3.7)	(2.2)
Net loss on sales of investments and other assets	(1.2)	(0.6)
Total special items	$ (90.2)	$ (21.9)

Loss from Discontinued Operations

During 2004, we completed the sale of a geothermal facility in Hawaii. We recorded a loss of $77.7 million pre-tax, or $50.4 million after-tax, during the year ended December 31, 2004. We reported the after-tax loss as a component of "Loss from discontinued operations" in our Consolidated Statements of Income. Additionally, prior to sale we recognized earnings from the facility of $2.1 million pre-tax, or $1.3 million after-tax as a component of "Loss from discontinued operations." We discuss the loss from discontinued operations in more detail in *Note 2*.

Synthetic Fuel Tax Credits

We have investments in facilities that manufacture solid synthetic fuel produced from coal as defined under Section 29 of the Internal Revenue Code for which we can claim tax credits on our Federal income tax return until 2007. We recognize the tax benefit of these credits in our Consolidated Statements of Income when we believe it is highly probable that the credits will be sustained.

As of December 31, 2004, we have recognized cumulative tax benefits associated with Section 29 credits of $201.2 million. In 2004, we recognized $123.2 million in tax benefits for Section 29 credits, including $35.9 million for credits relating to 2003 production. We discuss the synthetic fuel tax credits in more detail in *Note 10.*

Workforce Reduction Costs

In the fourth quarter of 2004, we approved a restructuring of the work forces of the Nine Mile Point and Calvert Cliffs nuclear generating facilities that was effective in January 2005.

In connection with this restructuring, approximately 108 employees will receive severance and other benefits under our existing benefit programs. We accrued the estimated total cost of this reduction in workforce of $9.7 million pre-tax, or $5.9 million after-tax, in accordance with applicable accounting requirements. We expect to realize annual savings in the future from reduced labor and benefit costs approximately equal to the charge recorded in 2004.

Impairment of Financial Investment

Our other nonregulated businesses recognized a pre-tax impairment loss of $3.7 million, or $2.2 million after-tax, during the year ended December 31, 2004 related to an other than temporary decline in fair value of certain financial investments.

Net Loss on Sales of Investments and Other Assets

Our other nonregulated businesses recognized a net pre-tax loss of $1.2 million, or $0.6 million after-tax, during the year ended December 31, 2004 on the sales of non-core assets. We discuss our net loss on sales of investments and other assets in more detail in *Note 2*.

Acquisition

In June 2004, we completed our purchase of the R. E. Ginna nuclear facility (Ginna), which is located in Ontario, New York from Rochester Gas & Electric Corporation (RG&E). Ginna consists of a 495 megawatt reactor that entered service in 1970 and is licensed to operate until 2029. We discuss the acquisition further in *Note 15*.

Dividend Increase

In January 2005, we announced an increase in our quarterly dividend to $0.335 per share on our common stock. This is equivalent to an annual rate of $1.34 per share. Previously, our quarterly dividend on our common stock was $0.285 per share, equivalent to an annual rate of $1.14 per share.

Results of Operations

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. Significant changes in other income and expense, fixed charges, and income taxes are discussed in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section.

Overview

Results

	2004	2003	2002
		(In millions, after-tax)	
Merchant energy	**$ 439.0**	$ 313.0	$ 247.2
Regulated electric	**131.1**	107.5	99.3
Regulated gas	**22.2**	43.0	31.1
Other nonregulated	**(3.5)**	12.2	148.0

	2004	2003	2002
Net Income Before Cumulative Effects of Changes in Accounting Principles	**588.8**	475.7	525.6
Loss from discontinued operations	**(49.1)**		
Cumulative effects of changes in accounting principles		(198.4)	
Net Income	**$ 539.7**	$ 277.3	$ 525.6
Special Items Included in Operations:			
Recognition of 2003 synthetic fuel tax credits	**$ 35.9**	$	$
Workforce reduction costs	**(5.9)**	(1.3)	(38.0)
Impairments of real estate, senior-living, and other investments	**(2.2)**	(0.4)	(1.2)
Net (loss) gain on sales of investments and other assets	**(0.6)**	16.4	166.7
Impairments of investment in qualifying facilities and domestic power projects			(9.9)
Costs associated with exit of BGE Home merchandise stores			(6.1)
Total Special Items	**$ 27.2**	$ 14.7	$ 111.5

2004

Our total net income for 2004 increased $262.4 million, or $1.46 per share, compared to the same period of 2003 mostly because of the following:

In 2003, we recorded a $266.1 million after-tax, or $1.60 per share, loss for the cumulative effect of adopting EITF 02-3. This was partially offset by a $67.7 million after-tax, or $0.41 per share, gain for the cumulative effect of adopting Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations*. These items had a combined negative impact during 2003.

Our merchant energy business had higher earnings of $78.4 million at our South Carolina synfuel facility primarily due to the recognition of $35.9 million in tax credits associated with 2003 production and tax credits associated with 2004 production.

We had higher earnings from our regulated electric business mostly because of the absence of $19.4 million of after-tax incremental operations and maintenance expenses due to distribution service restoration efforts associated with Hurricane Isabel in 2003.

We had higher earnings from our nuclear generating assets due to the June 2004 acquisition of Ginna, which contributed $28.1 million after-tax, and higher generation at our Calvert Cliffs nuclear power plant, partially offset by lower generation by and lower power prices for the output of our Nine Mile Point facility in 2004 compared to 2003.

We had higher earnings from our merchant energy business mostly due to the realization of wholesale contracts originated in prior periods, portfolio management, and favorable settlements at our retail electric operation of $16.9 million pre-tax.

We had higher earnings due to lower pre-tax losses of $47.7 million associated with economic hedges that do not qualify for cash-flow hedge accounting treatment.

We had higher earnings of $20.9 million after-tax in 2004 due to a full year of operations at the High Desert facility.

These increases were partially offset by the following:

We recorded a $49.1 million after-tax, or $0.28 per share, loss from discontinued operations.

We had higher Sarbanes-Oxley 404 implementation costs of approximately $15 million pre-tax, higher enterprise information systems expenditures of approximately $8 million pre-tax, and higher compensation, benefit, and other inflationary cost increases.

We had lower earnings from our regulated gas business mostly because of $13.6 million after-tax of higher operations and maintenance expenses in 2004 and the absence of a $4.7 million after-tax market-based rate gas recovery, which had a favorable effect in 2003.

We recognized a gain of $16.4 million after-tax related to non-core asset sales in 2003 that had a favorable impact in that period.

Earnings per share was impacted by additional dilution resulting from the issuance of 6.0 million shares of common stock on July 1, 2004.

2003

Our total net income for 2003 decreased $248.3 million, or $1.54 per share, compared to 2002 mostly because of the following:

We recorded a $266.1 million after-tax, or $1.60 per share, charge for the cumulative effect of adopting EITF 02-3. This was partially offset by a $67.7 million after-tax, or $0.41 per share, gain for the cumulative effect of adopting SFAS No. 143.

We recognized a $163.3 million after-tax, or $1.00 per share, gain on the sale of our investment in Orion Power Holdings, Inc. (Orion) in 2002 that had a positive impact in that period. We discuss the sale of Orion in more detail in *Note 2*.

We had higher fixed charges of $58.7 million due to lower capitalized interest of $30.2 million and $28.5 million primarily related to a higher level of debt outstanding as a result of refinancing our High Desert facility.

Our results reflect the impact of the shift to accrual accounting under EITF 02-3. Specifically, the absence of 2002 mark-to-market gains for contracts accounted for on an accrual basis in 2003 and the timing difference in the recognition of earnings for certain economic hedges, which we discuss further in the *Competitive Supply Mark-to-Market Revenues* section, were only partially offset by the 2003 recognition of accrual earnings on transactions entered into in prior periods.

Our regulated electric business incurred incremental distribution service restoration expenses of $19.4 million after-tax associated with Hurricane Isabel.

These decreases were partially offset by the following:

We had higher earnings from wholesale competitive supply activities including effective portfolio management, partially offset by lower mark-to-market origination in 2003.

We had $39.5 million of higher earnings from our regulated business, excluding the impacts of Hurricane Isabel.

We had higher earnings from favorable generating plant operational performance. Specifically, our High Desert facility commenced operations in April 2003 contributing $39.1 million after-tax, and Calvert Cliffs completed a steam generator replacement in April 2003, 58 fewer days than a similar outage that was completed in June 2002.

We had $36.7 million after-tax of higher workforce reduction costs in 2002 that had a negative impact in the period.

We realized cost reductions due to productivity initiatives.

We had higher earnings from a full year at our retail electric operation, which contributed $20.3 million, and from the acquisition of our retail gas operation, which contributed $4.1 million.

Our other nonregulated business recognized a gain of $16.4 million after-tax, or $0.10 per share, in 2003 related to non-core asset sales.

We had higher earnings from our other nonregulated businesses primarily related to improved operations of our international portfolio of $7.0 million after-tax.

We had $6.1 million after-tax of costs associated with our exit of BGE Home merchandise stores in 2002 that had a negative impact in that period.

We recognized impairments of certain investments in qualifying facilities, real estate, and other investments in 2002 that had a negative impact in that period.

Merchant Energy Business

Background

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

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

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

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

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

Mark-to-market accounting requires us to make estimates and assumptions using judgment in determining the fair value of certain 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. We discuss mark-to-market accounting and the accounting policies for the merchant energy business further in the *Critical Accounting Policies* section and in *Note 1*.

In the first quarter of 2003, we adopted EITF 02-3, which required non-derivative contracts to be accounted for on the accrual basis and recorded in our Consolidated Statements of Income gross rather than net. The primary contracts affected were our full requirements load-serving contracts and unit-contingent power purchase contracts. The majority of these contracts were in Texas and New England and were entered into prior to our shift to accrual accounting earlier in 2002. We discuss our shift to accrual accounting during 2002 in more detail in the *Wholesale Accrual Activities* section. 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 by a similar increase in fuel and purchased energy expenses.

EITF 02-3 affects the timing of recognizing earnings on non-derivative transactions. Earnings on new non-derivative 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.

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

Results

	2004	**2003**	**2002**
		(In millions)	
Revenues	**$ 10,389.9**	$ 7,632.9	$ 2,781.3
Fuel and purchased energy expenses	**(8,129.3)**	(5,706.1)	(1,208.3)
Operating expenses	**(1,178.4)**	(935.9)	(759.8)
Workforce reduction costs	**(9.7)**	(1.2)	(26.5)
Impairment losses and other costs			(14.4)
Depreciation and amortization	**(248.0)**	(229.5)	(242.8)
Accretion of asset retirement obligations	**(53.2)**	(42.7)	
Taxes other than income taxes	**(91.5)**	(89.2)	(69.7)
Net loss on sales of assets			(3.7)

	2004	2003	2002
Income from Operations	**$ 679.8**	$ 628.3	$ 456.1
Income from continuing operations before cumulative effects of changes in accounting principles (after-tax)	**$ 439.0**	$ 313.0	$ 247.2
Loss from discontinued operations (after-tax)	**(49.1)**		
Cumulative effects of changes in accounting principles (after-tax)		(198.4)	
Net Income	**$ 389.9**	$ 114.6	$ 247.2
Special Items Included in Operations (after-tax)			
Recognition of 2003 synthetic fuel tax credits	**$ 35.9**	$	$
Workforce reduction costs	**(5.9)**	(0.7)	(16.0)
Impairment of investments in qualifying facilities and domestic power projects			(9.9)
Net loss on sales of assets			(2.4)
Total Special Items	**$ 30.0**	$ (0.7)	$ (28.3)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements. Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Revenues and Fuel and Purchased Energy Expenses

Our merchant energy business manages the revenues we realize from the sale of energy to our customers and our costs of procuring fuel and energy. The difference between revenues and fuel and purchased energy expenses is the gross margin of our merchant energy business, and this measure is management's primary tool for assessing the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in gross margin between periods. In managing our portfolio, we occasionally terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

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

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

Plants with Power Purchase Agreements our generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements, including the Nine Mile Point, Ginna, Oleander, University Park, and High Desert facilities.

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

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

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

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

		2004		2003		2002
				(Dollar amounts in millions)		
Revenues:						
Mid-Atlantic Region	**$**	**1,925.6**	$	1,696.2	$	1,415.1
Plants with Power Purchase Agreements		**756.9**		620.0		456.4
Competitive Supply						
Retail		**4,280.0**		2,567.7		312.7
Wholesale		**3,353.8**		2,703.9		540.7
Other		**73.6**		45.1		56.4
Total	**$**	**10,389.9**	$	7,632.9	$	2,781.3
Fuel and purchased energy expenses:						
Mid-Atlantic Region	**$**	**(946.9)**	$	(711.6)	$	(551.2)
Plants with Power Purchase Agreements		**(57.6)**		(51.9)		(40.0)
Competitive Supply						
Retail		**(4,011.4)**		(2,389.5)		(273.2)
Wholesale		**(3,113.4)**		(2,553.1)		(343.9)
Other						
Total	**$**	**(8,129.3)**	$	(5,706.1)	$	(1,208.3)
				% of Total		**% of Total**

Gross margin:	2004	% of Total	2003		2002	
Mid-Atlantic Region	**$ 978.7**	**43%**	$ 984.6	51%	$ 863.9	55%
Plants with Power Purchase Agreements	**699.3**	**31**	568.1	29	416.4	26
Competitive Supply						
Retail	**268.6**	**12**	178.2	9	39.5	3
Wholesale	**240.4**	**11**	150.8	8	196.8	13
Other	**73.6**	**3**	45.1	3	56.4	3
Total	**$ 2,260.6**	**100%**	$ 1,926.8	100%	$ 1,573.0	100%

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

Mid-Atlantic Region

	2004	2003	2002
		(In millions)	
Revenues	**$ 1,925.6**	$ 1,696.2	$ 1,415.1
Fuel and purchased energy expenses	**(946.9)**	(711.6)	(551.2)
Gross margin	**$ 978.7**	$ 984.6	$ 863.9

The decrease in Mid-Atlantic Region gross margin in 2004 compared to 2003 is primarily due to lower fossil plant availability resulting in lower margin of $17.0 million and higher coal costs primarily due to purchasing coal from alternative suppliers in 2004 at higher prices than in 2003 as a result of delays in deliveries as discussed in the *Business Environment Other Factors* section. These decreases were partially offset by an increase in margin of $7.1 million related to new load-serving obligations, offset in part by lower volumes served to BGE resulting from small commercial customers leaving BGE's standard offer service due to the end of fixed-price service in June 2004.

The increase in Mid-Atlantic Region gross margin in 2003 compared to 2002 is primarily due to:

- higher margins of approximately $85 million from our owned generation in excess of that used to serve BGE's standard offer service, including our active portfolio management of these generating assets and associated physical and financial arrangements, and
- a gain on the assumption of the Allegheny Energy Supply Company, L.L.C. load-serving contract for the remaining 10% of the BGE standard offer service load.

Plants with Power Purchase Agreements

	2004	2003	2002
		(In millions)	
Revenues	**$ 756.9**	$ 620.0	$ 456.4
Fuel and purchased energy expenses	**(57.6)**	(51.9)	(40.0)
Gross margin	**$ 699.3**	$ 568.1	$ 416.4

The increase in gross margin from our Plants with Power Purchase Agreements in 2004 compared to 2003 is primarily due to:

- gross margin of $112.4 million from Ginna, which was acquired in June 2004. The increase in gross margin includes higher revenues of $119.1 million. We discuss this acquisition in more detail in *Note 14,* and
- higher gross margin of $45.9 million from the High Desert facility that contributed a full year of gross margin in 2004 compared to eight months in 2003.

These increases in gross margin were partially offset by lower gross margin of $21.0 million at our Nine Mile Point facility primarily due to lower revenues from reduced contract prices for the output in 2004 compared to 2003 and lower generation.

The increase in gross margin from our Plants with Power Purchase Agreements in 2003 compared to 2002 is primarily due to:

- gross margin of $105.5 million from the High Desert facility, which commenced operations in the second quarter of 2003. The increase in gross margin includes higher revenues of $111.3 million,
- higher gross margin of $22.6 million from Nine Mile Point primarily due to fewer forced outage days in 2003 compared to 2002, and
- higher gross margin of $18.7 million from the Oleander generating facility that contributed a full year of gross margin during 2003 compared to six months of operations during 2002.

Competitive Supply

Retail

	2004	2003	2002
		(In millions)	

	2004	2003	2002
Accrual revenues	**$ 4,281.0**	$ 2,567.7	$ 312.7
Mark-to-market revenues	**(1.0)**		
Fuel and purchased energy expenses	**(4,011.4)**	(2,389.5)	(273.2)
Gross margin	**$ 268.6**	$ 178.2	$ 39.5

The increase in gross margin from our retail competitive supply activities in 2004 compared to 2003 is primarily due to higher electric gross margin of $66.1 million mostly due to:

- serving approximately 16 million more megawatt hours partially offset by lower realized margins due to increased wholesale power costs in 2004 compared to 2003,
- a bankruptcy settlement from PG&E of $10.3 million, and a favorable settlement of a pre-acquisition liability of $6.6 million also related to a bankruptcy proceeding, and
- lower contract amortization, which reduces margin, of $9.2 million relating to the fair value of contracts at acquisition.

In addition, we had higher gas gross margin contribution of $17.1 million from Blackhawk Energy Services and Kaztex Energy Management, which were acquired in October 2003. We discuss our acquisitions in more detail in *Note 15*.

The increase in gross margin from our retail competitive supply activities in 2003 compared to 2002 is due to:

- a full year of electric gross margin contribution of $115.9 million. The increase in electric gross margin includes higher revenues of $1,170.2 million. Our retail electric operation was acquired in September 2002, and
- a full year of gas gross margin contribution of $22.8 million. The increase in gas gross margin includes higher revenues of $1,084.8 million. Our retail gas operation was acquired in December 2002.

Wholesale

	2004	2003	2002
		(In millions)	
Accrual revenues	**$ 3,253.7**	$ 2,667.7	$ 310.7
Fuel and purchased energy expenses	**(3,113.4)**	(2,553.1)	(343.9)
Wholesale accrual activities	**140.3**	114.6	(33.2)
Mark-to-market revenues	**100.1**	36.2	230.0
Gross margin	**$ 240.4**	$ 150.8	$ 196.8

In January 2003, we adopted EITF 02-3 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. During 2002, the majority of our wholesale results were on the mark-to-market method of accounting.

The portion of competitive supply revenues, fuel and purchased energy expenses, and gross margin derived from accrual and mark-to-market contracts changed significantly due to the adoption of EITF 02-3. Effective January 1, 2003, we began to account for all non-derivative contracts on the accrual basis, whereas we had accounted for these contracts on the mark-to-market basis in 2002. We also began to recognize origination gains only for derivative contracts for which we have observable market prices. These changes increased accrual competitive supply revenues, fuel and purchased energy expenses, and gross margin and decreased mark-to-market competitive supply revenues and gross margin in 2003 as compared to 2002.

EITF 02-3 affected a large number of competitive supply contracts, and we cannot quantify its total impact precisely because we cannot recast our 2002 results to reflect accrual accounting, nor did we maintain separate mark-to-market accounting records for accrual contracts beginning in 2003. However, the larger portion of our competitive supply activities that became subject to accrual accounting under EITF 02-3 resulted in an increase in total competitive supply revenues and fuel and purchased energy expenses, but a decrease in total competitive supply gross margin in 2003 compared to 2002.

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

Wholesale Accrual Activities

The increase in gross margin from our wholesale accrual activities in 2004 compared to 2003 is primarily due to approximately $50 million in the New England region due to higher realized contract margins in 2004 compared to 2003 and higher volumes served. This increase was partially offset by higher transportation costs for our gas trading portfolio of approximately $16 million. The transportation costs associated with this portfolio are accounted for on an accrual basis, while our gas trading portfolio is recorded as mark-to-market. In addition, we incurred higher operating costs of $5.0 million related to our South Carolina synthetic fuel facility.

The increase in revenues, fuel and purchased energy expenses, and gross margin from our wholesale accrual activities in 2003 compared to 2002 is primarily due to the impact of the adoption of EITF 02-3 as discussed above. While it is not practicable to determine precisely the impact of EITF 02-3 on revenues and gross margin, accrual revenues for 2003 include approximately $1.4 billion from load-serving contracts that existed at January 1, 2003 (the date EITF 02-3 was adopted) which had been accounted for on a mark-to-market basis in 2002.

In addition, our wholesale accrual revenues and fuel and purchased energy expenses were impacted in 2002 by the re-designation of our Texas and New England load-serving activities to accrual.

In February 2002, we began to manage our Texas load-serving activities as a physical delivery business separate from our trading activities and re-designated these activities as non-trading. After the change in designation, the results of our Texas load-serving activities are included in "Nonregulated revenues" on a gross basis as power is delivered to our customers and "Fuel and purchased energy expenses" as costs are incurred. Prior to the re-designation, the results of these activities were reported on a net basis as part of mark-to-market revenues included in "Nonregulated revenues." Mark-to-market revenues for the Texas trading activities were a net loss of $1.2 million for the portion of 2002 prior to designation as non-trading.

Since future power sales revenues and costs from these activities are reflected in our Consolidated Statements of Income as part of "Nonregulated revenues" when power is delivered and "Fuel and purchased energy expenses" when the costs are incurred, this re-designation generally delays the recognition of earnings from these activities compared to what we would have recognized under mark-to-market accounting. The change in designation of our Texas load-serving activities did not impact our cash flows.

In addition, our New England load-serving activities consist primarily of contracts to serve the full energy and capacity requirements of retail customers and electric distribution utilities and associated power purchase agreements to supply our customers' requirements. We manage these activities primarily to assure profitable delivery of customers' energy requirements rather than as a traditional proprietary trading activity where profits or losses result from taking directional positions on market price changes. Therefore, we use accrual accounting for New England load-serving transactions and associated power purchase agreements entered into since the second quarter of 2002.

Because applicable accounting rules significantly limited the circumstances under which contracts previously designated as a trading activity could be re-designated as non-trading, prior to EITF 02-3, we were required to continue to include contracts entered into before the second quarter of 2002 in our mark-to-market accounting portfolio. However, under EITF 02-3, on January 1, 2003, we removed these contracts from our "Mark-to-market energy assets and liabilities" and began to account for these contracts under the accrual method of accounting.

Mark-to-Market Revenues

Mark-to-market revenues include net gains and losses from origination and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section and in *Note 1*. We also discuss the implications of EITF 02-3 on the mark-to-market method of accounting in the *Critical Accounting Policies* section.

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

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

Mark-to-market revenues were as follows:

	2004	2003	2002
		(In millions)	
Unrealized revenues			
Origination gains	**$ 19.7**	$ 62.3	$ 160.4
Risk management			
Unrealized changes in fair value	**79.4**	(26.1)	58.8
Changes in valuation techniques			10.8
Reclassification of settled contracts to realized	**(85.4)**	(123.5)	(45.4)
Total risk management	**(6.0)**	(149.6)	24.2
Total unrealized revenues*	**13.7**	(87.3)	184.6
Realized revenues	**85.4**	123.5	45.4
Total mark-to-market revenues	**$ 99.1**	$ 36.2	$ 230.0

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

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

Origination gains represent the initial fair value recognized on these structured transactions. The recognition of origination gains is dependent on the existence of observable market data that validates the initial fair value of the contract. Origination gains arose from 13 transactions completed in 2004 and 14 transactions completed in 2003, of which no transaction individually contributed in excess of $10 million pre-tax.

As noted on the previous page, the recognition of origination gains is dependent on sufficient observable market data. Liquidity and market conditions impact our ability to identify sufficient, objective market-price information to permit recognition of origination gains. As a result, while our strategy and competitive position provide the opportunity to continue to originate such transactions, the level of origination revenue we are able to recognize may vary from year to year as a result of the number, size, and market-price transparency of the individual transactions executed in any period.

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

Our mark-to-market revenues were and continue to be affected by a decrease in the portion of our activities that is subject to mark-to-market accounting. As previously discussed in the *Wholesale Accrual Activities* section, we re-designated our Texas load-serving activities as accrual during 2002, and we began to account for new non-derivative origination transactions on the accrual basis rather than under mark-to-market accounting. Beginning January 1, 2003, under EITF 02-3, we no longer record existing non-derivative contracts at fair value. Further, effective July 1, 2002, to the extent that we are not able to observe quoted market prices or other current market transactions for contract values determined using models, we record a valuation adjustment to result in zero gain or loss at inception. We remove the valuation adjustment in determining fair value when we obtain current market information for contracts with similar terms and counterparties.

Mark-to-market revenues increased $62.9 million in 2004 compared to 2003 mostly because of the impact of lower mark-to-market losses on economic hedges that do not qualify for hedge accounting treatment as discussed in more detail on the next page and lower losses from risk management activities primarily due to favorable changes in regional power prices, and price volatility. These increases were partially offset by a lower level of origination gains in 2004 compared to 2003. The lower level of origination gains is primarily due to higher individually significant gains on contracts in 2003 that had a positive impact in that period.

Mark-to-market revenues decreased $193.8 million in 2003 compared to 2002 mostly because of lower revenues from origination transactions, net losses from risk management activities compared to net gains in the prior year, and the reclassification of revenues from settled contracts to realized revenues. The lower level of origination transactions primarily reflects the continuing reduction of the portion of our activities subject to mark-to-market accounting. The decrease in risk management revenues is primarily due to mark-to-market revenue associated with the restructuring of our High Desert contract with the CDWR that had a positive impact in 2002, unfavorable changes in regional power prices, price volatility, and the impact of mark-to-market losses on economic hedges that did not qualify for hedge accounting treatment as discussed in more detail below.

With the implementation of EITF 02-3 in the first quarter of 2003, all of our load-serving contracts were converted to accrual accounting. However, several economically effective hedges on these positions did not qualify for accrual accounting treatment under SFAS No. 133 and remained in the mark-to-market portfolio. In 2003, increasing forward prices shifted value between accrual load-serving positions and associated mark-to-market hedges producing a timing difference in the recognition of earnings on related transactions. As a result, we recorded $0.3 million of pre-tax gains in 2004 and $47.4 million of pre-tax losses on the mark-to-market hedges during 2003. This mark-to-market loss will be offset as we realize the related accrual load-serving positions in cash.

Mark-to-Market Energy Assets and Liabilities

Our mark-to-market energy assets and liabilities are comprised of derivative contracts. While some of our mark-to-market contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We discuss our modeling techniques later in this section.

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

At December 31,	**2004**	2003
	(In millions)	
Current Assets	**$ 567.3**	$ 504.8
Noncurrent Assets	**359.8**	265.8
Total Assets	**927.1**	770.6
Current Liabilities	**559.7**	490.4
Noncurrent Liabilities	**315.0**	261.4
Total Liabilities	**874.7**	751.8
Net mark-to-market energy asset	**$ 52.4**	$ 18.8

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

The following are the primary sources of the change in net mark-to-market energy asset during 2004 and 2003:

	2004		2003	
		(In millions)		
Fair value beginning of year		**$ 18.8**		$ 516.6
Changes in fair value recorded as revenues				
Origination gains	**$ 19.7**		$ 62.3	
Unrealized changes in fair value	**79.4**		(26.1)	
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(85.4)**		(123.5)	
Total changes in fair value recorded as revenues		**13.7**		(87.3)
Cumulative effect impact of EITF 02-3				(379.4)
Contracts designated as normal purchases/sales and hedges upon implementation of EITF 02-3				(58.2)

	2004	2003
Contract exchange		(68.9)
Changes in value of exchange-listed futures and options	**(15.8)**	(8.4)
Net change in premiums on options	**29.4**	99.3
Other changes in fair value	**6.3**	5.1
Fair value at end of year	**$ 52.4**	$ 18.8

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

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

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

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

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

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

The cumulative effect impact of EITF 02-3 represents the non-derivative portion of the net asset that was removed from our Consolidated Balance Sheets as a cumulative effect of change in accounting principle effective January 1, 2003 as required by EITF 02-3.

Contracts designated as normal purchases/sales and hedges upon implementation of EITF 02-3 represents the portion of the net asset reclassified to "Other assets or liabilities" under the normal purchases/normal sales provisions of SFAS No. 133 or "Risk management assets or liabilities" under the cash-flow hedge provisions of SFAS No. 133 in connection with the implementation of EITF 02-3 effective January 1, 2003.

Contract exchange represents the fair value of a contract previously included in "Mark-to-market energy assets" that we terminated in a nonmonetary exchange with a counterparty. At that time, we also terminated a hedge contract with the same counterparty that was recorded in "Risk management liabilities." In exchange, we entered into a new cash-flow hedge transaction with the counterparty that we recorded at an amount equal to the fair value of the terminated contracts.

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

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

The settlement terms of our net mark-to-market energy asset and sources of fair value as of December 31, 2004 are as follows:

	Settlement Term							
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Fair Value**
				(In millions)				
Prices provided by external sources (1)	$ 17.2	$ 29.5	$ 123.0	$ 61.6	$	$	$	$ 231.3
Prices based on models	(9.6)	(8.3)	(101.7)	(54.6)	(1.5)	(1.8)	(1.4)	(178.9)
Total net mark-to-market energy asset	$ 7.6	$ 21.2	$ 21.3	$ 7.0	$ (1.5)	$ (1.8)	$ (1.4)	$ 52.4

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

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

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

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

forward purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2006, but up to 2008, depending upon the region,

options for the purchase and sale of electricity during peak hours for delivery terms through 2005, depending upon the region,

forward purchases and sales of electric capacity for delivery terms through 2006,

forward purchases and sales of natural gas, coal and oil for delivery terms through 2008, and

options for the purchase and sale of natural gas, coal and oil for delivery terms through 2006.

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

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

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

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

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

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

The fair values in the table represent expected future cash flows based on the level of forward prices and volatility factors as of December 31, 2004 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets vary substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

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

<u>Other</u>

	2004	**2003**	**2002**
		(In millions)	
Revenues	**$ 73.6**	$ 45.1	$ 56.4

Our merchant energy business holds up to a 50% voting interest in 24 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 24 projects, 17 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policy Act of 1978 based on the facilities' energy source or the use of a cogeneration process. Earnings from our investments were $18.0 million in 2004, $2.1 million in 2003, and $9.1 million in 2002.

The increase in revenues in 2004 compared to 2003 is primarily due to higher equity in earnings related to our minority investment in a facility that produces synthetic fuel from coal. This increase included $13.1 million of revenues related to an increased incentive fee and a deferred contingent transaction fee.

The decrease in revenues in 2003 compared to 2002 was due to lower revenues from our California projects because we reversed certain credit reserves that totaled $9.1 million during the first quarter of 2002, as we began receiving payments from the California utilities, which had a positive impact in 2002, partially offset by a geothermal project generating at a higher capacity in 2003.

At December 31, 2004, our investment in qualifying facilities and domestic power projects consisted of the following:

Book Value at December 31,	**2004**	**2003**
	(In millions)	
Project Type		
Coal	**$ 128.7**	$ 130.5
Hydroelectric	**55.8**	57.3
Geothermal	**46.3**	56.0
Biomass	**50.2**	51.4
Fuel Processing	**22.5**	22.5
Solar	**10.4**	10.5
Total	**$ 313.9**	$ 328.2

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, and fuel processing projects provide sufficient positive cash flows to recover our investments. We continuously monitor issues that potentially could impact future profitability of these investments, including environmental and legislative initiatives. We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* section. However, should future events cause these investments to become uneconomic, our investments in these projects could become impaired under the provisions of APB No. 18.

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

Given the need for electric power and the desire for renewable resource technologies, we believe California will continue to subsidize the use of renewable energy to make these projects economical to operate. However, should the California legislation fail to adequately support the renewable energy initiatives, our equity-method investments in these types of projects could become impaired under the provisions of APB No. 18, and any losses recognized could be material. If our strategy were to change from an intent to hold to an intent to sell for any of our equity-method investments in qualifying facilities or power projects, we would need to adjust their book value to fair value, and that adjustment could be material. If we were to sell these investments in the current market, we may have losses that could be material.

Operating Expenses

Our merchant energy business operating expenses increased $242.5 million in 2004 compared to 2003 mostly due to the following:

- an increase of $94.3 million primarily related to higher compensation, benefit, and other inflationary costs, higher Sarbanes-Oxley 404 implementation costs of approximately $10 million, and higher spending on enterprise-wide information technology infrastructure costs of approximately $5 million,
- an increase at our competitive supply operations totaling $90.1 million mostly because of higher compensation and benefit expense, including an increased number of employees to support the growth of these operations,
- an increase in expenses due to the June 2004 acquisition of Ginna totaling $43.1 million, and
- an increase of $10.1 million at our Nine Mile Point nuclear facility primarily due to refueling outage and reliability spending.

Our merchant energy business operating expenses increased $176.1 million in 2003 compared to 2002 mostly due to the following:

- an increase of $81.5 million due to the acquisitions of our retail electric operation in September 2002 and retail gas operation in December 2002,
- an increase of $22.7 million at Nine Mile Point, including higher costs associated with the refueling outage of Unit 1 in 2003 compared to the 2002 refueling outage of Unit 2. Since we own 100% of Unit 1, we incurred all outage costs compared to 82% of costs for Unit 2,
- costs of $17.8 million related to our High Desert facility that commenced operations in the second quarter of 2003,
- an increase in costs of $10.3 million related to our wholesale marketing and risk management operation as a result of growth of this operation, and
- higher compensation, benefit, and other inflationary costs.

These increases were partially offset by cost reductions due to productivity initiatives including our corporate-wide workforce reduction programs.

Workforce Reduction Costs, Impairment Losses and Other Costs, and Net Loss on Sales of Assets

Our merchant energy business recognized expenses associated with our loss on discontinued operations, workforce reduction efforts, impairment losses and other costs, and a net loss on sales of assets as discussed in more detail in *Note 2*.

Depreciation and Amortization Expense

Merchant energy depreciation and amortization expense increased $18.5 million in 2004 compared to 2003 mostly because of $10.3 million of depreciation and amortization at Ginna which was acquired in June 2004 and $5.1 million related to our South Carolina synthetic fuel facility which was acquired in May 2003.

Merchant energy depreciation and amortization expense decreased $13.3 million in 2003 compared to 2002 mostly because of the adoption of SFAS No. 143. Under SFAS No. 143, a portion of the decommissioning amortization is included as "Accretion of asset retirement obligations" expense beginning in 2003. In addition, beginning in 2003 we no longer include the expected net future costs of removal as a component of depreciation expense. These decreases were partially offset by higher depreciation expense related to new generating facilities that commenced operations in mid-2002 and High Desert that commenced operations in 2003.

Accretion of Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143 that requires the accretion of the asset retirement obligation liability due to the passage of time until the liability is settled. The increase in accretion expense of $10.5 million in 2004 compared to 2003 is primarily due to $6.9 million related to Ginna which was acquired in June 2004.

Taxes Other Than Income Taxes

Merchant energy taxes other than income taxes increased $2.3 million in 2004 compared to 2003 mostly because of $4.2 million of property taxes at Ginna which was acquired in June 2004, partially offset by lower property taxes at Nine Mile Point.

Merchant energy taxes other than income taxes increased $19.5 million in 2003 compared to 2002 mostly because of gross receipt taxes associated with our retail electric operation of $17.5 million and property taxes on new generating facilities.

Regulated Electric Business

Our regulated electric business is discussed in detail in *Item 1. Business Electric Business* section.

Results

		2004		2003		2002
				(In millions)		
Revenues	**$**	**1,967.7**	$	1,921.6	$	1,966.0
Electricity purchased for resale expenses		**(1,034.0)**		(1,023.5)		(1,080.7)
Operations and maintenance expenses		**(304.2)**		(305.1)		(260.4)
Workforce reduction costs				(0.6)		(34.0)
Depreciation and amortization		**(194.2)**		(181.7)		(174.2)
Taxes other than income taxes		**(132.8)**		(130.2)		(129.0)
Income from Operations	**$**	**302.5**	$	280.5	$	287.7
Net Income	**$**	**131.1**	$	107.5	$	99.3
Special Items Included in Operations (after-tax)						
Workforce reduction costs	**$**		$	(0.4)	$	(20.5)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements. Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Net income from the regulated electric business increased in 2004 compared to 2003 mostly because of:

- increased revenues less electricity purchased for resale expenses of $21.5 million after-tax in 2004 compared to 2003, which includes $6.0 million after-tax related to the shareholder return portion of the administrative fee collected under Provider of Last Resort rates,
- the absence of $19.4 million after-tax of incremental distribution service restoration expenses associated with Hurricane Isabel in 2003, and
- lower interest expense of $10.0 million after-tax.

These favorable results were partially offset by the following:

- excluding the costs associated with Hurricane Isabel, we had increased operations and maintenance expenses of $18.9 million after-tax in 2004 compared to 2003 mostly due to higher compensation, benefit, and other inflationary costs, higher uncollectible expenses, Sarbanes-Oxley 404 implementation costs, and increased spending on electric system reliability, and
- increased depreciation and amortization expense of $7.6 million after-tax.

Net income from the regulated electric business increased in 2003 compared to 2002 mostly because of:

- lower workforce reduction costs of $20.1 million after-tax,
- lower interest expense of $19.1 million after-tax, and
- cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

These favorable results were partially offset by distribution service restoration expenses related to Hurricane Isabel and other major storms in 2003. Total distribution service restoration expenses related to Hurricane Isabel were $22.2 million after-tax, which included $19.4 million of incremental expenses.

Electric Revenues

The changes in electric revenues in 2004 and 2003 compared to the respective prior year were caused by:

		2004		2003
		(In millions)		
Distribution volumes	$	**15.8**	$	3.0
Standard offer service		**26.6**		(54.2)
Total change in electric revenues from electric system sales		**42.4**		(51.2)
Other		**3.7**		6.8
Total change in electric revenues	$	**46.1**	$	(44.4)

Distribution Volumes

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

The percentage changes in our electric system distribution volumes, by type of customer, in 2004 and 2003 compared to the respective prior year were:

	2004	2003
Residential	**4.4%**	0.8%
Commercial	**0.9**	2.1
Industrial	**(8.0)**	(3.0)

In 2004, we distributed more electricity to residential customers compared to 2003 mostly due to increased usage per customer, an increased number of customers, and warmer summer weather. We distributed about the same amount of electricity to commercial customers. We distributed less electricity to industrial customers mostly due to lower usage by industrial customers.

In 2003, we distributed about the same amount of electricity to residential customers compared to 2002. We distributed more electricity to commercial customers mostly due to increased usage per customer. We distributed less electricity to industrial customers mostly due to lower usage by industrial customers.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative generation supplier as discussed in *Item 1. Business Electric Regulatory Matters and Competition* section.

Standard offer service revenues increased in 2004 compared to 2003 mostly because of increased distribution volumes to residential customers, partially offset by lower revenues associated with commercial and industrial customers that elected an alternative supplier beginning July 1, 2004. Standard offer service revenues decreased in 2003 compared to 2002 mostly because a majority of BGE's large commercial and industrial customers left standard offer service in the second quarter of 2002 and elected other electric generation suppliers. In 2003, these decreased revenues were partially offset by an increase in the standard offer service rate that BGE charges its customers.

Electricity Purchased for Resale Expenses

BGE's actual costs of electricity purchased for resale expenses increased in 2004 compared to 2003 mostly due to increased sales to residential customers, partially offset by lower electricity purchased for resale expenses associated with commercial and industrial customers that elected an alternative supplier beginning July 1, 2004. Electricity purchased for resale expenses decreased in 2003 compared to 2002 mostly because large commercial and industrial customers left BGE's standard offer service in the second quarter of 2002 and elected other electric generation suppliers.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses were about the same in 2004 compared to 2003. Hurricane Isabel caused $32.1 million of incremental distribution service restoration expenses in 2003. Other operations and maintenance expenses increased $31.2 million in 2004 compared to 2003. This increase was mostly due to:

- an increase in compensation, benefit, and other inflationary costs,
- a $9.0 million increase in uncollectible expenses,
- approximately $4 million related to Sarbanes-Oxley 404 implementation costs, and
- approximately $4 million in spending on electric systems reliability.

Regulated electric operations and maintenance expenses increased $44.7 million in 2003 compared to 2002 mostly because of distribution service restoration expenses related to Hurricane Isabel of $36.8 million, which includes $4.7 million of non-incremental labor expenses, and distribution service restoration expenses related to other major storms. This increase also reflects higher compensation, benefit, and other inflationary costs, partially offset by lower uncollectible expenses and cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

Workforce Reduction Costs

BGE's electric business recognized expenses associated with our workforce reduction efforts as discussed in *Note 2*.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense increased $12.5 million in 2004 compared to 2003 mostly because of $7.6 million related to accelerated amortization expense associated with the replacement of information technology assets and $4.9 million related to additional property placed in service.

Regulated electric depreciation and amortization expense increased $7.5 million in 2003 compared to 2002 mostly because of accelerated amortization associated with the replacement of information technology assets.

Regulated Gas Business

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

Results

	2004	2003	2002
		(In millions)	
Revenues	**$ 757.0**	$ 726.0	$ 581.3
Gas purchased for resale expenses	**(484.3)**	(445.8)	(316.7)
Operations and maintenance expenses	**(123.6)**	(101.1)	(106.2)
Workforce reduction costs		(0.1)	(1.3)
Depreciation and amortization	**(48.1)**	(46.6)	(47.4)
Taxes other than income taxes	**(32.1)**	(27.9)	(31.1)
Income from Operations	**$ 68.9**	$ 104.5	$ 78.6
Net Income	**$ 22.2**	$ 43.0	$ 31.1
Special Items Included in Operations (after-tax)			
Workforce reduction costs	**$**	$ (0.1)	$ (0.8)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements. Certain prior-year amounts have been reclassified to conform with the current year's presentation.

Net income from our regulated gas business decreased during 2004 compared to 2003 mostly because of:

- increased operations and maintenance expenses of $13.6 million after-tax mostly due to increased compensation, benefit, and other inflationary costs, higher uncollectible expenses, and Sarbanes-Oxley 404 implementation costs,
- the absence of a $4.7 million after-tax recovery of a previously disallowed regulatory asset following an order issued by the Maryland PSC that had a positive impact in 2003, and
- the absence of $2.2 million after-tax of property tax refund claims by the State of Maryland resulting from a reclassification of gas distribution pipeline from real property to personal property that had a positive impact in 2003.

Net income from our regulated gas business increased during 2003 compared to 2002 mostly because of:

- a $4.7 million after-tax recovery of a previously disallowed regulatory asset following an order issued by the Maryland PSC, and
- the approval of $2.2 million after-tax of property tax refund claims by the State of Maryland resulting from a reclassification of gas distribution pipeline from real property to personal property.

Gas Revenues

The changes in gas revenues in 2004 and 2003 compared to the respective prior year were caused by:

	2004	2003

	2004	2003
	(In millions)	
Distribution volumes	**$ (7.2)**	$ 21.6
Base rates	**(0.1)**	(1.3)
Weather normalization	**5.4**	(18.9)
Gas cost adjustments	**40.5**	132.4
Total change in gas revenues from gas system sales	**38.6**	133.8
Off-system sales	**(7.6)**	10.0
Other		0.9
Total change in gas revenues	**$ 31.0**	$ 144.7

Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2004 and 2003 compared to the respective prior year were:

	2004	2003
Residential	(5.1)%	13.8%
Commercial	10.1	7.6
Industrial	(22.3)	(21.5)

We distributed less gas to residential customers during 2004 compared to 2003 mostly due to milder winter weather and lower usage per customer. We distributed more gas to commercial customers mostly due to increased usage and an increased number of customers. We distributed less gas to industrial customers mostly due to lower usage per customer.

We distributed more gas to residential and commercial customers during 2003 compared to 2002 mostly due to colder winter weather, an increased number of customers, and increased usage per customer. We distributed less gas to industrial customers mostly due to decreased usage per customer.

Weather Normalization

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

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in *Note 1*. However, under the market-based rates mechanism approved by the Maryland PSC, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

Customers who do not purchase gas from BGE are not subject to the gas cost adjustment clauses because we are not selling gas to them. However, these customers are charged base rates to recover the costs BGE incurs to deliver their gas through our distribution system, and are included in the gas distribution volume revenues.

Gas cost adjustment revenues increased during 2004 compared to 2003 because we sold gas at a higher price partially offset by less gas sold. Gas cost adjustment revenues increased during 2003 compared to 2002 because we sold more gas at a higher price.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order disallowing $7.7 million of a previously established regulatory asset for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the $7.7 million of disallowed fuel costs in the fourth quarter of 2002. In August 2003, the Maryland PSC issued an order authorizing us to recover the $7.7 million and we reinstated the regulatory asset.

Off-System Sales

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

Revenues from off-system gas sales decreased during 2004 compared to 2003 mostly because of less gas sold.

Revenues from off-system gas sales increased during 2003 compared to 2002 because we sold gas at a higher price, partially offset by less gas sold.

Gas Purchased For Resale Expenses

Gas purchased for resale expenses include the cost of gas purchased for resale to our customers and for off-system sales. These costs do not include the cost of gas purchased by delivery service only customers.

Gas costs increased during 2004 as compared to 2003 mostly because of higher average gas prices and the $7.7 million recovery of disallowed fuel-related costs recognized in 2003 that had a positive impact in that period as previously discussed in the *Gas Cost Adjustments* section.

Gas costs increased during 2003 as compared to 2002 mostly because we purchased more gas at a higher price.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased $22.5 million during 2004 compared to 2003 mostly because of:

- an increase in compensation, benefit, and other inflationary expenses,
- a $5.4 million increase in uncollectible expenses, and
- approximately $1 million related to Sarbanes-Oxley 404 implementation costs.

Regulated gas operations and maintenance expenses decreased $5.1 million during 2003 compared to 2002 mostly because of lower uncollectible expenses and cost reductions resulting from our corporate-wide workforce reduction programs and other productivity initiatives.

Workforce Reduction Costs

BGE's gas business recognized expenses associated with our workforce reduction efforts as discussed in *Note 2*.

Other Nonregulated Businesses

Results

	2004	2003	2002
		(In millions)	
Revenues	**$ 422.0**	$ 587.9	$ 537.4
Operating expenses	**(353.4)**	(535.8)	(505.9)
Workforce reduction costs		(0.2)	(1.0)
Impairment losses and other costs	**(3.7)**	(0.6)	(10.8)
Depreciation and amortization	**(35.2)**	(21.2)	(16.6)
Taxes other than income taxes	**(2.5)**	(3.3)	(4.3)
Net (loss) gain on sales of investments and other assets	**(1.2)**	26.2	265.0
Income from Operations	**$ 26.0**	$ 53.0	$ 263.8
Net (Loss) Income	**$ (3.5)**	$ 12.2	$ 148.0
Special Items Included In Operations (after-tax)			
Impairment of real estate, senior-living, and other investments	**$ (2.2)**	$ (0.4)	$ (1.2)
Net (loss) gain on sales of investments and other assets	**(0.6)**	16.4	169.1
Workforce reduction costs		(0.1)	(0.7)
Costs associated with exit of BGE Home merchandise stores			(6.1)
Total Special Items	**$ (2.8)**	$ 15.9	$ 161.1

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 3 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Net income from our other nonregulated businesses decreased $15.7 million during 2004 compared to 2003 mostly because of a $16.4 million net gain on sales of investments and other assets in 2003 that had a positive impact in that period.

Net income from our other nonregulated businesses decreased $135.8 million during 2003 compared to 2002 mostly because we recognized a $163.3 million after-tax gain on the sale of our investment in Orion in 2002 that had a positive impact in that period. This decrease was partially offset by the following 2003 transactions:

- a $13.1 million pre-tax gain on the sale of several parcels of real estate,
- a $9.5 million pre-tax charge associated with the exit of BGE Home merchandise stores in 2002 which had a negative impact in that period,
- a $7.2 million pre-tax gain on the sale of an oil tanker to the U.S. Navy,
- a $5.3 million pre-tax gain on the favorable settlement of a contingent obligation we had previously reserved relating to the sale of our Guatemalan power plant operation in the fourth quarter of 2001,
- a $0.6 million pre-tax gain on the sale of financial investments, and
- improved results from our international portfolio.

In 2001, we decided to sell certain non-core assets and accelerate the exit strategies on other assets that we continued to hold and own. These assets included approximately 1,300 acres of land holdings in various stages of development located in seven sites in the central Maryland region, an operating waste water treatment plant located in Anne Arundel County, Maryland, all of our 18 senior-living facilities and certain international power projects. At December 31, 2004, our remaining land holdings totaled approximately 190 acres with a carrying value of approximately $29 million recorded in our Consolidated Balance Sheets. We also initiated a liquidation program for our financial investments operation in 2001. As of December 31, 2004, we have substantially liquidated our investment portfolio and have approximately $6 million in non-core financial investments recorded in our Consolidated Balance Sheets.

In 2005, we began to market our Panamanian distribution facility and our investment in a fund that owns interests in two South American energy projects, with an expectation of completing a sale by the end of the year. We do not expect that the sale of these assets will have a material impact on our financial results.

While our intent is to dispose of these remaining non-core assets, market conditions and other events beyond our control may affect the actual sale of these assets. In addition, a future decline in the fair value of these assets could result in losses that could have a material impact on our financial results.

Consolidated Nonoperating Income and Expenses

Other Income

Other income decreased $5.0 million during 2004 as compared to 2003 mostly because of higher earnings from consolidated investments where our ownership is less than 100%, which resulted in increased minority interest expense. Other income decreased $11.4 million during 2003 as compared to 2002 mostly because of lower interest income on temporary cash investments of $6.1 million and higher earnings from consolidated investments where our ownership is less than 100%, which resulted in increased minority interest expense of $4.0 million.

Other income for BGE decreased $16.1 million in 2003 as compared to 2002 mostly because of an increase in charitable contributions of $7.5 million and because of lower interest income of $5.0 million on temporary cash investments in the Constellation Energy cash pool.

Fixed Charges

Total fixed charges decreased $9.9 million during 2004 as compared to 2003 mostly because of a lower level of debt outstanding and the benefit of lower interest rates due to interest rate swaps entered into during the third quarter of 2004. We discuss these interest rate swaps in more detail in *Note 13*.

Total fixed charges increased $58.7 million during 2003 compared to 2002 mostly because we had lower capitalized interest of $30.2 million due to our new generating facilities commencing operations and $28.5 million related to a higher level of debt outstanding, including the issuance of $550 million of debt in June 2003 that was used to refinance the High Desert facility lease.

Total fixed charges for BGE decreased $15.0 million during 2004 compared to 2003 mostly because of a lower level of debt outstanding. Total fixed charges for BGE decreased $29.4 million during 2003 compared to 2002 mostly because of a lower level of debt outstanding and lower interest rates.

Income Taxes

The differences in income taxes result from a combination of the changes in income and the impact of the recognition of tax credits on the effective tax rate. We include an analysis of the changes in the effective tax rate and discuss in more detail the tax credits related to our South Carolina synthetic fuel facility in *Note 10*.

Pension Expense

Our actual return on our qualified pension plan assets was 11.6% for the year ended December 31, 2004. We assume an expected return on pension plan assets of 9% for the purpose of computing annual net periodic pension expense in accordance with SFAS No. 87, *Employers' Accounting for Pensions*. Differences between actual and expected returns are deferred along with other actuarial gains and losses and reflected in future net periodic pension expense in accordance with SFAS No. 87. Expected and actual returns on pension assets also are affected by plan contributions.

We contributed an additional $50 million to our pension plans in March 2005, even though there is no IRS minimum contribution for 2005. At December 31, 2004, we recorded an after-tax charge to equity of $42.6 million as a result of increasing our additional minimum pension liability. We discuss our pension plans in more detail in *Note 7*.

Financial Condition

Cash Flows

The following table summarizes our 2004 cash flows by business segment, as well as our consolidated cash flows for 2004, 2003, and 2002.

	2004 Segment Cash Flows			Consolidated Cash Flows		
	Merchant	Regulated	Other	2004	2003	2002
			(In millions)			
Operating Activities						
Net Income	$ 389.9	$ 153.3	$ (3.5)	**$ 539.7**	$ 277.3	$ 525.6
Non-cash adjustments to net income	592.9	293.1	44.3	**930.3**	959.5	616.0
Changes in working capital	(318.8)	(43.1)	32.3	**(329.6)**	(65.3)	49.0
Pension and postemployment benefits*				**(3.0)**	(69.4)	(116.2)
Other	(41.2)	(28.0)	18.6	**(50.6)**	(44.3)	(68.6)
Net cash provided by operating activities	622.8	375.3	91.7	**1,086.8**	1,057.8	1,005.8
Investing activities						
Investments in property, plant and equipment	(428.3)	(242.1)	(33.2)	**(703.6)**	(635.7)	(817.7)
Acquisitions, net of cash acquired	(457.3)			**(457.3)**	(546.6)	(221.4)
Contributions to nuclear decommissioning trust funds	(22.0)			**(22.0)**	(13.2)	(17.6)
Net proceeds from sale of discontinued operations	72.7			**72.7**		
Sale of investments and other assets	0.1	4.9	31.1	**36.1**	148.8	838.0
Other investments	(86.1)		7.5	**(78.6)**	(113.6)	(86.9)
Net cash (used in) provided by investing activities	(920.9)	(237.2)	5.4	**(1,152.7)**	(1,160.3)	(305.6)
Cash flows from operating activities less cash flows from investing activities	$ (298.1)	$ 138.1	$ 97.1	**(65.9)**	(102.5)	700.2
Financing Activities						
Net (repayment) issuance of debt*				**(152.8)**	274.9	(62.9)
Proceeds from issuance of common stock*				**293.9**	95.4	28.5
Common stock dividends paid*				**(189.7)**	(169.2)	(137.8)
Other*				**99.5**	7.7	14.6
Net cash provided by (used in) financing activities				**50.9**	208.8	(157.6)
Net (Decrease) Increase in Cash and Cash Equivalents				**$ (15.0)**	$ 106.3	$ 542.6

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

Cash Flows from Operating Activities

Cash provided by operating activities was $1,086.8 million in 2004 compared to $1,057.8 million in 2003 and $1,005.8 million in 2002. Net income was higher by $262.4 million in 2004 compared to 2003. Non-cash adjustments to net income were $29.2 million lower in 2004 compared to 2003. The decrease in non-cash adjustments to net income was primarily due to the cumulative effects of changes in accounting principles of $198.4 million as a result of the adoption of SFAS No. 143 and EITF 02-3 in 2003, which had the effect of reducing net income in 2003 but were non-cash transactions. This decrease in non-cash adjustments to net income was offset in part by the following increases in non-cash adjustments in 2004:

- higher depreciation and amortization and accretion of asset retirement obligations of $60 million,
- the loss from discontinued operations of $49 million,
- an increase in deferred income taxes of $14 million, and

- a decrease in the net gain on sales of investments and other assets of $27 million primarily due to the sale of financial and real estate investments in 2003. We adjust net income to exclude these gains and reflect the proceeds from these sales in the investing activities section.

Changes in working capital had a negative impact of $329.6 million on cash flow from operations in 2004 compared to a negative impact of $65.3 million in 2003. The $264.3 million decrease was primarily due to the following uses of cash in 2004 compared to 2003:

- a decline in working capital related to accrued taxes of approximately $254 million in 2004 compared to 2003 due to higher income tax payments in 2004 compared to refunds of taxes in 2003 and due to the timing of income tax accruals in 2004 compared to 2003,
- a $77 million unfavorable change in working capital relating to our accounts receivable and accounts payable primarily due to increased volumes associated with our merchant energy business and the termination of an accounts receivable securitization program in 2004, and

an unfavorable change of approximately $49 million relating to fuel stocks during 2004 primarily due to higher gas and coal prices, which affected inventory levels at BGE and our merchant energy business.

These items were partially offset by a $111 million source of cash in 2004 compared to 2003 primarily due to other favorable working capital changes as a result of higher accrued expenses in 2004 compared to 2003.

Cash provided by operating activities was $1,057.8 million in 2003 compared to $1,005.8 million in 2002. Non-cash adjustments to net income were $343.5 million higher in 2003 compared to 2002. The increase in non-cash adjustments to net income was primarily due to the following:

cumulative effects of changes in accounting principles of $198.4 million as a result of the adoption of SFAS No. 143 and EITF 02-3 in 2003, which had the effect of reducing net income but were non-cash transactions, and

a decrease in the net gain on sales of investments and other assets of $235.1 million primarily due to the sale of our investment in Orion in 2002.

These increases in non-cash adjustments to net income were offset in part by lower accruals for workforce reduction costs of $60.7 million in 2003 compared to 2002.

Changes in working capital had a negative impact of $65.3 million on cash flow from operations in 2003 compared to a positive impact of $49.0 million in 2002. The $114.3 million decrease was primarily due to the following uses of cash in 2003 compared to 2002:

an increase in cash in 2002 due to the collection of approximately $85 million related to prepaid expenses and collateral at our retail electric operation subsequent to our acquisition,

a decline in accrued interest of approximately $50 million in 2003 compared to 2002 due to a shift in the timing of interest payments as a result of financings in 2002,

an increase of approximately $40 million in fuel stocks and materials and supplies during 2003 primarily due to higher gas prices, which affected BGE's inventory levels, and

an increase of approximately $54 million in our accounts receivable balance primarily related to our merchant energy business as a result of increased business and High Desert commencing operations in 2003.

These items were partially offset by a source of cash in 2003 compared to 2002 due to an increase in accrued income taxes.

Cash Flows from Investing Activities

Cash used in investing activities was $1,152.7 million in 2004 compared to $1,160.3 million in 2003 and $305.6 million in 2002. Cash used in investing activities in 2004 was about the same as in 2003 primarily due to the decrease in cash used for acquisitions and proceeds from the sale of discontinued operations in 2004, substantially offsetting increased spending on property, plant and equipment and a decrease in cash proceeds from the sale of investments and other assets in 2004 compared to 2003.

The $854.7 million increase in cash used in investing activities in 2003 compared to 2002 was primarily due to a decrease in cash proceeds from the sales of investments and other assets in 2003 because of the sale of Orion and Corporate Office Property Trust that generated $555.4 million in 2002. We discuss our sale of Orion in *Note 2*. In addition, acquisitions were $325.2 million higher in 2003 due to the refinancing of the High Desert lease, partially offset by a decline in other acquisitions from 2002.

Cash Flows from Financing Activities

Cash provided by financing activities was $50.9 million in 2004 compared to $208.8 million in 2003. The decrease in 2004 compared to 2003 was mostly due to a lower issuance of net debt in 2004 (gross proceeds less debt repayments), partially offset by higher proceeds from common stock issuances and acquired contracts in 2004. We discuss cash flows from customer contract restructurings in more detail below.

Cash provided by financing activities increased $366.4 million in 2003 compared to 2002 mostly due to higher net issuances of debt in 2003 compared to 2002.

Cash Flows from Customer Contract Restructurings

During 2004, our merchant energy business entered into several power agreements to help customers restructure their businesses, which generate significant cash flows at the inception of the contracts. These agreements have a contract price that differs from current market prices, which results in cash payments from the counterparty at the inception of the contract. We received $117.5 million in 2004 for one contract reflected in cash flows from financing activities in our Consolidated Statements of Cash Flows. We received an additional $157.2 million for a second contract in March 2005. We expect to receive approximately $70 million in the first half of 2005 for another contract that was entered into during 2004, contingent upon the receipt of all regulatory and other approvals and the closing of the transaction.

Security Ratings

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

The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, and the amount of debt as a component of total capitalization. In March 2004, Standard & Poors rating group reduced Constellation Energy's and BGE's corporate credit rating from A- to BBB+ and reduced certain other ratings to the levels noted in the table on the next page. In October 2004, Fitch-

Ratings affirmed Constellation Energy's and BGE's credit ratings. All Constellation Energy and BGE credit ratings have stable outlooks. At the date of this report, our credit ratings were as follows:

	Standard & Poors Rating Group	Moody's Investors Service	Fitch-Ratings
Constellation Energy			
Commercial Paper	A-2	P-2	F-2
Senior Unsecured Debt*	BBB	Baa1	A-
BGE			
Commercial Paper	A-2	P-1	F-1
Mortgage Bonds	A	A1	A+
Senior Unsecured Debt	BBB+	A2	A
Trust Preferred Securities*	BBB-	A3	A-
Preference Stock*	BBB-	Baa1	A-

** In March 2004, Standard & Poors rating group reduced the rating one level to this current rating.*

Available Sources of Funding

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

Constellation Energy

In addition to our cash balance, we have a commercial paper program under which we can issue short-term notes to fund our subsidiaries. At December 31, 2004, we had approximately $2.2 billion of credit under several facilities.

In June 2004, Constellation Energy arranged an $800.0 million three-year revolving credit facility and a $300.0 million five-year revolving credit facility replacing a $447.5 million 364-day revolving credit facility, which expired in the second quarter of 2004. We also have an existing $640 million revolving credit facility expiring in June 2005 and a $447.5 million facility expiring in June 2006.

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

These revolving credit facilities allow the issuance of letters of credit up to approximately $2.2 billion. In addition, BGE maintains $200.0 million in credit facilities as discussed below. At December 31, 2004, letters of credit that totaled $809.9 million were issued under all of our facilities.

In October 2004, we terminated certain loans under other revolving credit agreements of $41.4 million related to our Panamanian distribution facility. We replaced these revolving credit agreements with loans under new revolving credit agreements totaling $100.0 million.

We expect to fund future acquisitions with an overall goal of maintaining a strong investment grade credit profile. We funded our June 2004 acquisition of Ginna with a mix of cash and equity. On July 1, 2004, we issued 6.0 million shares of common stock for net proceeds of $226.9 million to fund a portion of the acquisition of Ginna. We discuss our acquisition of Ginna in more detail in *Note 15*.

BGE

During 2004, certain credit facilities expired and BGE renewed those facilities. BGE continues to maintain $200.0 million in annual committed credit facilities, expiring May through November 2005, to ensure adequate liquidity to support its operations. We can borrow directly from the banks or use the facilities to allow commercial paper to be issued. As of December 31, 2004, BGE had no outstanding commercial paper, which results in $200.0 million in unused credit facilities.

Other Nonregulated Businesses

BGE Home Products & Services' program to sell up to $50 million of receivables was not extended beyond the March 2004 expiration date. During 2004, this receivables program was fully liquidated.

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

Capital Resources

Our actual consolidated capital requirements for the years 2002 through 2004, along with the estimated annual amount for 2005, are shown in the table on the next page.

We will continue to have cash requirements for:

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

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

- regulation, legislation, and competition,
- BGE load requirements,
- environmental protection standards,
- the type and number of projects selected for construction or acquisition,
- the effect of market conditions on those projects,
- the cost and availability of capital,
- the availability of cash from operations, and
- business decisions to invest in capital projects.

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section.

	2002	2003	2004	2005
		(In millions)		
Nonregulated Capital Requirements:				
Merchant energy (excludes acquisitions)				
Construction program	$ 122	$	$	$
Generation plants	236	175(A)	182	180
Nuclear fuel	122	59	133	125
Environmental controls	66	12		5
Portfolio acquisitions/investments	51	51	11	140
Technology/other	44	122	129	125
Total merchant energy capital requirements	641	419	455	575
Other nonregulated capital requirements	65	53	42	35
Total nonregulated capital requirements	706	472	497	610
Regulated Capital Requirements:				
Regulated electric	167	236	209	250
Regulated gas	50	53	56	55
Total regulated capital requirements	217	289	265	305
Total capital requirements	$ 923	$ 761	$ 762	$ 915

(A)

The table above does not include the capital requirements and financing costs of approximately $40 million for the High Desert Power Project for the six months ended June 30, 2003. We discuss the acquisition of the High Desert Power Project in *Note 15*.

The above amounts do not include the acquisition of Ginna but do include post-acquisition capital requirements for Ginna. We discuss the acquisition of Ginna in more detail in Note 15.

As of the date of this report, we have not completed our 2006 capital budgeting process, but expect our 2006 capital requirements to be approximately $950 million.

Our environmental controls capital requirements are affected by new rules or regulations that require modifications to our facilities. As a result of regulatory or legislative proposals, we expect more stringent air emission standards to be adopted and if promulgated as expected we will install additional air emission control equipment at our coal-fired generating facilities in Maryland and at co-owned coal-fired generating facilities in Pennsylvania. If these rules are promulgated as we have assumed in our projections, there would be another $400-$500 million of capital spending from 2008-2010. We discuss environmental matters in more detail in *Item 1.Business Environmental Matters*.

Capital Requirements

Merchant Energy Business

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

improvements to generating plants,

nuclear fuel costs,

- upstream gas investments,
- portfolio acquisitions and other investments,
- costs of complying with the Environmental Protection Agency (EPA), Maryland, and Pennsylvania nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions regulations, and
- enhancements to our information technology infrastructure.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability. Capital requirements for 2003 in the table above include $32.0 million in costs incurred as a result of Hurricane Isabel to restore the electric distribution system.

Funding for Capital Requirements

Merchant Energy Business

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

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

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

Regulated Electric and Gas

Funding for regulated electric and gas capital expenditures is expected from internally generated funds. During 2005, we expect our regulated business to generate sufficient cash flows from operations to meet BGE's operating requirements. If necessary, additional funding may be obtained from commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust preferred securities, or preference stock, and/or from time to time equity contributions from Constellation Energy. BGE also participates in a cash pool administered by Constellation Energy as discussed in *Note 16*.

Other Nonregulated Businesses

Funding for our other nonregulated businesses is expected from internally generated funds, commercial paper issuances, issuances of long-term debt of Constellation Energy, sales of securities and assets, and/or from time to time equity contributions from Constellation Energy.

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

Contractual Payment Obligations and Committed Amounts

We enter into various agreements that result in contractual payment obligations in connection with our business activities. These obligations primarily relate to our financing arrangements (such as long-term debt, preference stock, and operating leases), purchases of capacity and energy to support the growth in our merchant energy business activities, and purchases of fuel and transportation to satisfy the fuel requirements of our power generating facilities.

Our total contractual payment obligations as of December 31, 2004 are shown in the following table:

	Payments				
	2005	2006-2007	2008-2009	Thereafter	Total
			(In millions)		
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 314.5	$ 639.6	$ 518.3	$ 2,328.1	$ 3,800.5
Interest	215.7	398.9	335.0	1,584.2	2,533.8
Total	530.2	1,038.5	853.3	3,912.3	6,334.3
BGE					
Principal	41.6	565.3	307.5	589.2	1,503.6
Interest	87.4	138.6	79.2	809.0	1,114.2
Total	129.0	703.9	386.7	1,398.2	2,617.8
BGE preference stock				190.0	190.0
Operating leases[2]	113.2	219.2	74.6	127.9	534.9
Purchase obligations:[3]					
Purchased capacity and energy[4]	794.2	743.3	184.9	157.0	1,879.4
Fuel and transportation[5]	1,292.0	816.3	142.8	37.3	2,288.4
Other	97.2	63.0	74.9	211.0	446.1
Other noncurrent liabilities:					
Postretirement and postemployment benefits[6]	36.1	74.3	79.8	185.1	375.3
Other	1.6				1.6
Total contractual payment obligations	$ 2,993.5	$ 3,658.5	$ 1,797.0	$ 6,218.8	$ 14,667.8

1 *Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $381.6 million early through put options and remarketing features. Interest on variable rate debt is included based on the December 31, 2004 forward curve for interest rates.*

2 *Our operating lease commitments include future payment obligations under certain power purchase agreements as discussed further in Note 11.*

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

4 *Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements. We have recorded $17.4 million of liabilities related to purchased capacity and energy obligations at December 31, 2004 in our Consolidated Balance Sheets.*

5 *We have recorded liabilities of $16.5 million related to fuel and transportation obligations at December 31, 2004 in our Consolidated Balance Sheets.*

6 *Amounts related to postretirement and postemployment benefits are for unfunded plans and reflect present value amounts consistent with the determination of the related liabilities recorded on the Consolidated Balance Sheets as discussed in Note 7.*

The table below presents our contingent obligations. Our contingent obligations increased $2.6 billion during 2004, primarily due to the issuance of additional letters of credit and guarantees by the parent company for subsidiary obligations to third parties in support of the growth of our merchant energy business. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties. Our calculation of the fair value of subsidiary obligations covered by the $5,504.2 million of parent company guarantees was $1,395.6 million at December 31, 2004. Accordingly, if the parent company was required to fund subsidiary obligations, the total amount at current market prices is $1,395.6 million.

Expiration

	Expiration				
	2005	2006-2007	2008-2009	Thereafter	Total
	(In millions)				
Contingent Obligations					
Letters of credit	$ 787.5	$ 22.4	$	$	$ 809.9
Guarantees - competitive supply[1]	3,693.4	918.5	314.5	577.8	5,504.2
Other guarantees, net[2]	6.7	3.6	15.7	1,236.0	1,262.0
Total contingent obligations	$ 4,487.6	$ 944.5	$ 330.2	$ 1,813.8	$ 7,576.1

1 *While the face amount of these guarantees is $5,504.2 million, we would not expect to fund the full amount. In the event the parent were required to fulfill subsidiary obligations, our calculation of the fair value of obligations covered by these guarantees was $1,395.6 million at December 31, 2004.*

2 *Other guarantees in the above table are shown net of liabilities of $25.0 million recorded at December 31, 2004 in our Consolidated Balance Sheets.*

Liquidity Provisions

In many cases, customers of our merchant energy business rely on the creditworthiness of Constellation Energy. A decline below investment grade by Constellation Energy would negatively impact the business prospects of that operation.

We regularly review our liquidity needs to ensure that we have adequate facilities available to meet collateral requirements. This includes having liquidity available to meet margin requirements for our wholesale marketing and risk management operation and our retail competitive supply activities.

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

Under counterparty contracts related to our wholesale marketing and risk management operation, we are obligated to post collateral if Constellation Energy's senior unsecured credit ratings declined below established contractual levels. As a result of the ratings action taken by Standard & Poors rating agency in March 2004, we posted approximately $40 million in additional collateral during the first quarter of 2004 to support our wholesale marketing and risk management operational requirements. We discuss the Standard & Poors rating action in more detail in the *Financial Condition Securities Ratings* section.

Based on contractual provisions at December 31, 2004, we estimate that if Constellation Energy's senior unsecured debt were downgraded we would have the following additional collateral obligations:

Credit Ratings Downgraded to	**Incremental Obligations**	**Cumulative Obligations**
	(In millions)	
BBB-/Baa3	$ 13	$ 13
Below investment grade	662	675

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that could exceed the amounts specified above, which could be material. At December 31, 2004, we had approximately $1.6 billion of unused credit facilities and $706.3 million of cash available to meet potential collateral requirements.

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

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2004, the debt to capitalization ratios as defined in the credit agreements were no greater than 51%. Certain credit agreements of BGE contain provisions requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2004, the debt to capitalization ratio for BGE as defined in these credit agreements was 46%. At December 31, 2004, no amount was outstanding under these agreements.

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

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

We discuss our short-term credit facilities in *Note 8*, long-term debt in *Note 9*, lease requirements in *Note 11*, and commitments and guarantees in *Note 12*.

Off-Balance Sheet Arrangements

For financing and other business purposes, we utilize certain off-balance sheet arrangements that are not reflected in our Consolidated Balance Sheets. Such arrangements do not represent a significant part of our activities or a significant ongoing source of financing. We use these arrangements when they enable us to obtain financing or execute commercial transactions on favorable terms. As of December 31, 2004, we have no material off-balance sheet arrangements including:

- guarantees with third-parties that are subject to the initial recognition and measurement requirements of FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others*,
- retained interests in assets transferred to unconsolidated entities,
- derivative instruments indexed to our common stock, and classified as equity, or
- variable interests in unconsolidated entities that provide financing, liquidity, market risk or credit risk support, or engage in leasing, hedging or research and development services.

We discuss our guarantees in *Note 12*.

Market Risk

We are exposed to various risks, including, but not limited to, energy commodity price and volatility risk, credit risk, interest rate risk, equity price risk, foreign exchange risk, and operations risk. Our risk management program is based on established policies and procedures to manage these key business risks with a strong focus on the physical nature of our business. This program is predicated on a strong risk management culture combined with an effective system of internal controls.

Our Board of Directors and the Audit Committee of the Board oversee the risk management program, including the approval of risk management policies and establishment of risk limits. We have a Risk Management Department that is responsible for monitoring the key business risks, enforcing compliance with risk management policies and risk limits, as well as managing credit risk. The Risk Management Department reports to the Chief Risk Officer (CRO) who provides regular risk management updates to the Audit Committee and the Board of Directors.

We have a Risk Management Committee (RMC) that is responsible for establishing risk management policies, reviewing procedures for the identification, assessment, measurement and management of risks, and the monitoring and reporting of risk exposures. The RMC meets on a regular basis and is chaired by the CRO and consists of our Chief Executive Officer, our Chief Financial Officer and Chief Administrative Officer, our Executive Vice President of Corporate Strategy & Development, the President of Constellation Energy Commodities Group, and the President of Constellation Generation Group. In addition, the CRO coordinates with the risk management committees at the major operating subsidiaries that meet regularly to identify, assess, and quantify material risk issues and to develop strategies to manage these risks.

Interest Rate Risk

We are exposed to changes in interest rates as a result of financing through our issuance of variable-rate and fixed-rate debt and certain related interest rate swaps. We may use derivative instruments to manage our interest rate risks.

In July 2004, to optimize the mix of fixed and floating-rate debt, we entered into interest rate swaps relating to $450 million of our long-term debt. These fair value hedges effectively convert our current fixed-rate debt to a floating-rate instrument tied to the three month London Inter-Bank Offered Rate. Including the $450 million in interest rate swaps, approximately 15% of our long-term debt is floating-rate.

The following table provides information about our debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2005	2006	2007	2008	2009	Thereafter	Total	Fair value at Dec. 31, 2004
				(Dollar amounts in millions)				
Long-term debt								
Variable-rate debt	$ 8.6	$ 100.9	$ 5.0	$ 5.0	$ 10.0	$ 706.1	$ 835.6	$ 835.6
Average interest rate	4.26%	2.57%	5.53%	5.53%	5.53%	3.00%	3.07%	
Fixed-rate debt	$ 347.5(A)	$ 362.1	$ 736.9	$ 299.3	$ 511.5	$ 2,211.2	$ 4,468.5	$ 4,979.7
Average interest rate	7.61%	5.43%	6.49%	6.28%	6.12%	6.46%	6.43%	

(A)

Amount excludes $381.6 million of long-term debt that contains certain put options under which lenders could potentially require us to repay the debt prior to maturity of which $124.3 million is classified as current portion of long-term debt in our Consolidated Balance Sheets and in our Consolidated Statements of Capitalization.

Commodity Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and other commodities. These risks arise from our ownership and operation of power plants, the load-serving activities of BGE standard offer service and our competitive supply activities, and our origination and risk management activities. We discuss these risks separately for our merchant energy and our regulated businesses below.

Merchant Energy Business

Our merchant energy business is exposed to various risks in the competitive marketplace that may materially impact its financial results and affect our earnings. These risks include changes in commodity prices, imbalances in supply and demand, and operations risk.

Commodity Prices

Commodity price risk arises from:

- the potential for changes in the price of, and transportation costs for, electricity, natural gas, coal, and other commodities,
- the volatility of commodity prices, and
- changes in interest rates and foreign exchange rates.

A number of factors associated with the structure and operation of the energy markets significantly influence the level and volatility of prices for energy commodities and related derivative products. We use such commodities and contracts in our merchant energy business, and if we do not properly hedge the associated financial exposure, this commodity price volatility could affect our earnings. These factors include:

- seasonal daily and hourly changes in demand,
- extreme peak demands due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- 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 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.

Additionally, we have fuel requirements that are subject to future changes in coal, natural gas, and oil prices. Our power generation facilities purchase fuel under contracts or in the spot market. Fuel prices may be volatile and the price that can be obtained from power sales may not change at the same rate or in the same direction as changes in fuel costs. This could have a material adverse impact on our financial results.

Supply and Demand Risk

We are exposed to the risk that available sources of supply may differ from the amount of power demanded by our customers under fixed-price load-serving contracts. During periods of high demand, our power supplies may be insufficient to serve our customers' needs and could require us to purchase additional energy at higher prices. Alternatively, during periods of low demand, our power supplies may exceed our customers' needs and could result in us selling that excess energy at lower prices. Either of those circumstances could have a negative impact on our financial results.

We are also exposed to variations in the prices and required volumes of natural gas and coal we burn at our power plants to generate electricity. During periods of high demand on our generation assets, our fuel supplies may be insufficient and could require us to procure additional fuel at higher prices. Alternatively, during periods of low demand on our generation assets, our fuel supplies may exceed our needs, and could result in us selling the excess fuels at lower prices. Either of these circumstances will have a negative impact on our financial results.

Operations Risk

Operations risk is the risk that a generating plant will not be available to produce energy and the risks related to physical delivery of energy to meet our customers' needs. For 2005, we expect to use the majority of the generating capacity controlled by our merchant energy business to provide standard offer service to BGE or to serve the load requirements of the sellers of Nine Mile Point and Ginna.

If one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sales commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices. We purchase power from generating facilities we do not own. If one or more of those generating facilities were unable to produce electricity due to operational factors, we may be forced to purchase electricity in the wholesale market at higher prices. This could have a material adverse impact on our financial results.

Our nuclear plants produce electricity at a relatively low marginal cost. The Nine Mile Point and Ginna facilities each sell 90% of output under unit-contingent power purchase agreements (we have no obligation to provide power if the units are not available) to the previous owners. However, if an unplanned outage were to occur at Calvert Cliffs during periods when demand was high, we may have to purchase replacement power at potentially higher prices to meet our obligations, which could have a material adverse impact on our financial results.

Risk Management

As part of our overall portfolio, we manage the commodity price risk of our competitive supply activities and our electric generation facilities, including power sales, fuel and energy purchases, emission credits, interest rate and foreign currency risks, weather risk, and the market risk of outages. In order to manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel and energy, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date;
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity; and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations,
- fixing the price of a portion of anticipated fuel purchases for the operation of our power plants,
- fixing the price for a portion of anticipated energy purchases to supply our load-serving customers, and
- managing our exposure to interest rate risk and foreign currency exchange risks.

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

While some of the contracts we use to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. We use our best estimates to determine the fair value of commodity and derivative contracts we hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is likely that future market prices could vary from those used in recording mark-to-market energy assets and liabilities, and such variations could be material.

We measure the sensitivity of our wholesale marketing and risk management mark-to-market energy contracts to potential changes in market prices using value at risk. Value at risk is a statistical model that attempts to predict risk of loss based on historical market price volatility. We calculate value at risk using a historical variance/covariance technique that models option positions using a linear approximation of their value. Additionally, we estimate variances and correlation using historical commodity price changes over the most recent rolling three-month period. Our value at risk calculation includes all wholesale marketing and risk management mark-to-market energy assets and liabilities, including contracts for energy commodities and derivatives that result in physical settlement and contracts that require cash settlement.

The value at risk calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and our competitive supply load-serving activities. We manage these risks by monitoring our fuel and energy purchase requirements and our estimated contract sales volumes compared to associated supply arrangements. We also engage in hedging activities to manage these risks. We describe those risks and our hedging activities earlier in this section.

The value at risk amounts below represent the potential pre-tax loss in the fair value of our wholesale marketing and risk management mark-to-market energy assets and liabilities over one and ten-day holding periods.

Total Wholesale Value at Risk

For the year ended December 31,	**2004**	**2003**
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	**$ 4.4**	$ 3.7
Average	**3.7**	6.6
High	**7.8**	13.3
Low	**2.5**	2.7
95% Confidence Level, One-Day Holding Period		
Year end	**$ 3.4**	$ 2.8
Average	**2.8**	5.0
High	**5.9**	10.1
Low	**1.9**	2.1
95% Confidence Level, Ten-Day Holding Period		
Year end	**$ 10.7**	$ 8.8
Average	**9.0**	15.9
High	**18.7**	32.0
Low	**6.1**	6.5

Based on a 99% confidence interval, we would expect a one-day change in the fair value of the portfolio greater than or equal to the daily value at risk approximately once in every 100 days. In 2004, we experienced four instances where the actual daily mark-to-market change in portfolio value exceeded the predicted value at risk. On average, we expect to experience a change in value to our portfolio greater than our value at risk approximately three times in a calendar year. However, published market studies conclude that exceeding daily value at risk less than seven times in a one-year period is considered consistent with a 99% confidence interval.

The table above is the value at risk associated with our wholesale marketing and risk management operation's mark-to-market energy assets and liabilities, including both trading and non-trading activities. The following table details our value at risk for the trading portion of our wholesale marketing and risk management mark-to-market energy assets and liabilities over a one-day holding period at a 99% confidence level for 2004 and 2003:

Wholesale Trading Value at Risk

At December 31,	**2004**	**2003**
	(In millions)	
Average	**$ 2.6**	$ 4.6
High	**6.9**	10.9

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

Regulated Electric Business

BGE's residential base rates are frozen for a six-year period ending June 30, 2006, and its commercial and industrial base rates were frozen for a four-year period that ended June 30, 2004. The commodity and transmission components of rates are frozen for different time periods depending on the customer type and service options selected by customers.

Our wholesale marketing and risk management operation provided BGE with 100% of the energy and capacity required to meet its commercial and industrial standard offer service obligations through June 30, 2004, and provides 100% of the energy and capacity to meet its residential standard offer service obligations through June 30, 2006. Effective July 1, 2004, BGE executed one and two-year contracts for commercial and industrial electric power supply totaling approximately 2,300 megawatts. Our wholesale marketing and risk management operation will provide a significant portion of this electric power supply.

Bidding to supply BGE's standard offer service to commercial and industrial customers for one, two, or four-year periods beyond June 30, 2004, and to residential customers beyond June 30, 2006, will occur from time to time through a competitive bidding process approved by the Maryland PSC. We discuss standard offer service and the impact on base rates in more detail in *Item 1. Business Electric Business* section.

BGE may receive performance assurance collateral from suppliers to mitigate suppliers' credit risks in certain circumstances. Performance assurance collateral is designed to protect BGE's potential exposure over the term of the supply contracts and will fluctuate to reflect changes in market prices. In addition to the collateral provisions, there are supplier "step-up" provisions, where other suppliers can step in if the early termination of a Full-Requirements Service Agreement with a supplier should occur, as well as specific mechanisms for BGE to otherwise replace defaulted supplier contracts. All costs incurred by BGE to replace the supply contract are to be recovered from the defaulting supplier or from customers through rates. Finally, BGE's exposure to uncollectible expense or credit risk from customers for the commodity portion of the bill is covered by the administrative fee included in Provider of Last Resort rates.

Regulated Gas Business

Our regulated gas business may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program. We discuss this further in *Note 13*. At December 31, 2004 and 2003, our exposure to commodity price risk for our regulated gas business was not material.

Credit Risk

We are exposed to credit risk, primarily through our merchant energy business. Credit risk is the loss that may result from counterparties' nonperformance. We evaluate the credit risk of our wholesale marketing and risk management operation and our retail competitive supply activities separately as discussed below.

Wholesale Credit Risk

We measure wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual) adjusted for amounts owed to or due from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where we have a legally enforceable right of setoff. We monitor and manage the credit risk of our wholesale marketing and risk management operation through credit policies and procedures which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral, or prepayment arrangements, and the use of master netting agreements.

During 2004, we continued to observe declines in the creditworthiness of several major participants in the wholesale energy markets. We continue to actively manage the credit portfolio of our wholesale marketing and risk management operation to attempt to reduce the impact of the general decline in the overall credit quality of the energy industry and the impact of a potential counterparty default. As of December 31, 2004 and 2003, the credit portfolio of our wholesale marketing and risk management operation had the following public credit ratings:

At December 31,	2004	2003
Rating		
Investment Grade[1]	**62%**	75%
Non-Investment Grade	**15**	4
Not Rated	**23**	21

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

The reduction in the percentage of counterparties with investment grade ratings to 62% in 2004 is primarily due to continued increased exposure to lower credit quality fuel and power supply counterparties that supply fuel to our power plants and provide power to meet certain customer load-serving requirements.

In addition to the credit ratings provided by the major credit rating agencies, we utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings.

At December 31,	2004	2003
Investment Grade Equivalent	**74%**	91%
Non-Investment Grade	**26**	9

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

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure

Rating	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
		(Dollars in millions)			
Investment grade	$ 789	$ 53	$ 736	1	$ 158
Split rating	6		6		
Non-investment grade	215	151	64		
Internally rated investment grade	225	58	167		
Internally rated non-investment grade	77	33	44		
Total	$ 1,312	$ 295	$ 1,017	1	$ 158

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract (for example, fail to deliver the electricity our wholesale marketing and risk management operation had contracted for), we could incur a loss that could have a material impact on our financial results.

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

Retail Credit Risk

We are exposed to retail credit risk through our competitive electricity and natural gas supply activities which serve commercial and industrial companies. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's accounts receivable balance, as well as the loss from the resale of energy previously committed to serve the customer.

Retail credit risk is managed through established credit policies, monitoring customer exposures, and the use of credit mitigation measures such as letters of credit or prepayment arrangements.

Our retail credit portfolio is well diversified with no significant company or industry concentrations. During 2004, we did not experience a material change in the credit quality of our retail credit portfolio compared to 2003. Retail credit quality is dependent on the economy and the ability of our customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, our retail credit risk may be adversely impacted.

Foreign Currency Risk

Our merchant energy business is exposed to the impact of foreign exchange rate fluctuations. This foreign currency risk arises from our activities in countries where we transact in currencies other than the U.S. dollar. In 2004, our exposure to foreign currency risk was not material. However, we expect our foreign currency exposure to grow due to our Canadian presence and international coal operations. We manage our exposure to foreign currency exchange rate risk using a comprehensive foreign currency hedging program. While we cannot predict currency fluctuations, the impact of foreign currency exchange rate risk could be material.

Equity Price Risk

We are exposed to price fluctuations in equity markets primarily through our pension plan assets, our nuclear decommissioning trust funds and trust assets securing certain executive benefits. We are required by the NRC to maintain externally funded trusts for the costs of decommissioning our nuclear power plants. We discuss our nuclear decommissioning trust funds in more detail in *Note 1*.

A hypothetical 10% decrease in equity prices would result in an approximate $110 million reduction in the fair value of our financial investments that are classified as trading or available-for-sale securities. In 2004, the value of our defined benefit pension plan assets increased by $114 million due to advances in the markets in which plan assets are invested. We describe our financial investments in more detail in *Note 4*, and our pension plans in *Note 7*.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item with respect to market risk is set forth in *Item 7* of Part II of this Form 10-K under the heading *Market Risk*.

Item 8. Financial Statements and Supplementary Data

REPORT OF MANAGEMENT

Financial Statements

The management of Constellation Energy Group, Inc. and Baltimore Gas and Electric Company (the "Companies") is responsible for the information and representations in the Companies' financial statements. The Companies prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the financial statements and expressed their opinion on them. They performed their audit in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Audit Committee of the Board of Directors, which consists of four independent Directors, meets periodically with management, internal auditors, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. The internal audit staff and PricewaterhouseCoopers LLP have free access to the Audit Committee.

Management's Report on Internal Control Over Financial Reporting

The management of Constellation Energy Group, Inc. ("Constellation Energy"), under the direction of its principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

Constellation Energy's system of internal control over financial reporting is designed to provide reasonable assurance to Constellation Energy's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of Constellation Energy conducted an evaluation of the effectiveness of Constellation Energy's internal control over financial reporting using the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that Constellation Energy's internal control over financial reporting was effective as of December 31, 2004.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited management's assessment of the effectiveness of Constellation Energy's internal control over financial reporting at December 31, 2004, as stated in their report set forth below.

As discussed in *Item 9A. Controls and Procedures*, the management of Baltimore Gas & Electric Company ("BGE") has not assessed the effectiveness of BGE's internal control over financial reporting on a standalone basis because it is not yet required to do so by applicable federal securities laws and regulations.

Mayo A. Shattuck III	E. Follin Smith
Chairman of the Board, President and Chief Executive Officer	*Executive Vice-President, Chief Financial Officer, and Chief Administrative Officer*

REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Constellation Energy Group, Inc.

We have completed an integrated audit of Constellation Energy Group, Inc. and Subsidiaries' 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) 1. present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and Subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) 2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of Constellation Energy Group, Inc. and Subsidiaries as of December 31, 2002, 2001 and 2000, and the related consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income for the years ended December 31, 2001 and 2000 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Constellation Energy Group, Inc. and Subsidiaries included in the Selected Financial Data for each of the five years in the period ended December 31, 2004, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Atlanta, Georgia
March 10, 2005

To Board of Directors and Shareholder of Baltimore Gas and Electric Company

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) 1. present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and Subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) 2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

We have also previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Baltimore Gas and Electric Company and Subsidiaries as of December 31, 2002, 2001 and 2000, and the related consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income for the years ended December 31, 2001 and 2000 (none of which are presented herein); and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Summary of Operations and Summary of Financial Condition of Baltimore Gas and Electric Company and Subsidiaries included in the Selected Financial Data for each of the five years in the period ended December 31, 2004, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

PricewaterhouseCoopers LLP
Atlanta, Georgia
March 10, 2005

CONSOLIDATED STATEMENTS OF INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	**2004**	**2003**	**2002**
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$ 9,827.0**	$ 7,053.6	$ 2,182.5
Regulated electric revenues	**1,967.6**	1,921.5	1,965.6
Regulated gas revenues	**755.1**	712.7	570.5
Total revenues	**12,549.7**	9,687.8	4,718.6
Expenses			
Fuel and purchased energy expenses	**8,849.6**	6,297.1	1,709.8
Operating expenses	**1,770.7**	1,575.6	1,380.8
Workforce reduction costs	**9.7**	2.1	62.8
Impairment losses and other costs	**3.7**	0.6	25.2
Depreciation and amortization	**525.5**	479.0	481.0
Accretion of asset retirement obligations	**53.2**	42.7	
Taxes other than income taxes	**258.9**	250.6	234.1
Total expenses	**11,471.3**	8,647.7	3,893.7
Net (Loss) Gain on Sales of Investments and Other Assets	**(1.2)**	26.2	261.3
Income from Operations	**1,077.2**	1,066.3	1,086.2
Other Income	**14.1**	19.1	30.5
Fixed Charges			
Interest expense	**328.0**	340.8	312.3
Interest capitalized and allowance for borrowed funds used during construction	**(10.9)**	(13.8)	(44.0)
BGE preference stock dividends	**13.2**	13.2	13.2
Total fixed charges	**330.3**	340.2	281.5
Income Before Income Taxes	**761.0**	745.2	835.2
Income Taxes	**172.2**	269.5	309.6
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**588.8**	475.7	525.6
Loss from discontinued operations, net of income taxes of $26.5 (see Note 2)	**(49.1)**		
Cumulative effects of changes in accounting principles, net of income taxes of $119.5		(198.4)	
Net Income	**$ 539.7**	$ 277.3	$ 525.6
Earnings Applicable to Common Stock	**$ 539.7**	$ 277.3	$ 525.6
Average Shares of Common Stock Outstanding Basic	**172.1**	166.3	164.2

Year Ended December 31,	2004	2003	2002
Average Shares of Common Stock Outstanding Diluted	**173.1**	166.7	164.2
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Basic	**$ 3.42**	$ 2.86	$ 3.20
Loss from discontinued operations	**(0.28)**		
Cumulative effects of changes in accounting principles		(1.19)	
Earnings Per Common Share Basic	**$ 3.14**	$ 1.67	$ 3.20
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Diluted	**$ 3.40**	$ 2.85	$ 3.20
Loss from discontinued operations	**(0.28)**		
Cumulative effects of changes in accounting principles		(1.19)	
Earnings Per Common Share Diluted	**$ 3.12**	$ 1.66	$ 3.20
Dividends Declared Per Common Share	**$ 1.14**	$ 1.04	$ 0.96

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2004**	2003
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 706.3**	$ 721.3
Accounts receivable (net of allowance for uncollectibles of **$43.1** and $51.7, respectively)	**1,979.3**	1,563.0
Mark-to-market energy assets	**567.3**	504.8
Risk management assets	**471.5**	233.0
Materials and supplies	**203.8**	203.2
Fuel stocks	**298.3**	196.8
Other	**262.9**	220.3
Total current assets	**4,489.4**	3,642.4
Investments and Other Assets		
Nuclear decommissioning trust funds	**1,033.7**	736.1
Investments in qualifying facilities and power projects	**318.4**	332.6
Mark-to-market energy assets	**359.8**	265.8
Risk management assets	**306.2**	154.5
Regulatory assets (net)	**195.4**	229.5
Goodwill	**144.8**	146.3
Other	**412.8**	484.3
Total investments and other assets	**2,771.1**	2,349.1
Property, Plant and Equipment		
Regulated property, plant and equipment		
Plant in service	**5,324.4**	5,131.7
Construction work in progress	**83.1**	130.5
Plant held for future use	**5.2**	4.5
Total regulated property, plant and equipment	**5,412.7**	5,266.7
Nonregulated property, plant and equipment	**8,638.4**	8,110.0
Nuclear fuel (net of amortization)	**264.3**	202.9
Accumulated depreciation	**(4,228.8)**	(3,978.1)
Net property, plant and equipment	**10,086.6**	9,601.5
Total Assets	**$ 17,347.1**	$ 15,593.0

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

CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2004**	2003
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$**	$ 9.6
Current portion of long-term debt	**480.4**	343.2
Accounts payable and accrued liabilities	**1,424.9**	1,142.0
Customer deposits and collateral	**223.8**	194.5
Mark-to-market energy liabilities	**559.7**	490.4
Risk management liabilities	**304.3**	118.8
Accrued expenses and other	**669.3**	628.9
Total current liabilities	**3,662.4**	2,927.4
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,303.3**	1,311.8
Asset retirement obligations	**825.0**	595.9
Mark-to-market energy liabilities	**315.0**	261.4
Risk management liabilities	**472.2**	166.7
Postretirement and postemployment benefits	**375.3**	361.8
Net pension liability	**269.7**	225.7
Deferred investment tax credits	**71.2**	78.4
Other	**232.0**	180.8
Total deferred credits and other liabilities	**3,863.7**	3,182.5
Capitalization (See Consolidated Statements of Capitalization)		
Long-term debt	**4,813.2**	5,039.2
Minority interests	**90.9**	113.4
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common shareholders' equity	**4,726.9**	4,140.5
Total capitalization	**9,821.0**	9,483.1
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 17,347.1**	$ 15,593.0

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2004	2003	2002
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 539.7**	$ 277.3	$ 525.6
Adjustments to reconcile to net cash provided by operating activities			
Loss from discontinued operations	**49.1**		
Cumulative effects of changes in accounting principles		198.4	
Depreciation and amortization	**660.7**	611.7	558.0
Accretion of asset retirement obligations	**53.2**	42.7	
Deferred income taxes	**123.4**	109.2	148.3
Investment tax credit adjustments	**(7.2)**	(7.3)	(7.9)
Deferred fuel costs	**6.0**	(10.1)	23.9
Pension and postemployment benefits	**(3.0)**	(69.4)	(116.2)
Net loss (gain) on sales of investments and other assets	**1.2**	(26.2)	(261.3)
Workforce reduction costs	**9.7**	2.1	62.8
Impairment losses and other costs	**3.7**	0.6	25.2
Equity in earnings of affiliates less than dividends received	**30.5**	38.4	67.0
Changes in			
Accounts receivable	**(437.4)**	(291.0)	(236.8)
Mark-to-market energy assets and liabilities	**(26.1)**	29.9	(133.7)
Risk management assets and liabilities	**5.3**	(83.5)	58.6
Materials, supplies, and fuel stocks	**(112.1)**	(51.5)	(11.7)
Other current assets	**2.4**	19.3	130.3
Accounts payable and accrued liabilities	**273.9**	204.1	188.4
Other current liabilities	**(35.6)**	107.4	53.9
Other	**(50.6)**	(44.3)	(68.6)
Net cash provided by operating activities	**1,086.8**	1,057.8	1,005.8
Cash Flows From Investing Activities			
Investments in property, plant and equipment	**(703.6)**	(635.7)	(817.7)
Acquisitions, net of cash acquired	**(457.3)**	(546.6)	(221.4)
Contributions to nuclear decommissioning trust funds	**(22.0)**	(13.2)	(17.6)
Net proceeds from sale of discontinued operations	**72.7**		
Sale of investments and other assets	**36.1**	148.8	838.0
Other investments	**(78.6)**	(113.6)	(86.9)
Net cash used in investing activities	**(1,152.7)**	(1,160.3)	(305.6)
Cash Flows From Financing Activities			
Net maturity of short-term borrowings	**(9.6)**	(0.9)	(964.5)
Proceeds from issuance of			
Common stock	**293.9**	95.4	28.5
Long-term debt	**100.0**	983.3	2,529.3
Repayment of long-term debt	**(243.2)**	(707.5)	(1,627.7)
Common stock dividends paid	**(189.7)**	(169.2)	(137.8)
Proceeds from acquired contracts	**117.5**		
Other	**(18.0)**	7.7	14.6
Net cash provided by (used in) financing activities	**50.9**	208.8	(157.6)

Year Ended December 31,	2004	2003	2002
Net (Decrease) Increase in Cash and Cash Equivalents	**(15.0)**	106.3	542.6
Cash and Cash Equivalents at Beginning of Year	**721.3**	615.0	72.4
Cash and Cash Equivalents at End of Year	**$ 706.3**	$ 721.3	$ 615.0
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 331.4**	$ 339.4	$ 230.5
Income taxes	**$ 207.9**	$ 34.0	$ 157.8

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31, 2004, 2003, and 2002	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Amount
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 2001	163,708	$ 2,042.2	$ 1,611.5	$ 189.9	$ 3,843.6
Comprehensive Income					
Net income			525.6		525.6
Other comprehensive income (OCI)					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $87.7				(152.8)	(152.8)
Reclassification of net gain on hedging instruments from OCI to net income, net of taxes of $10.9				(17.8)	(17.8)
Net unrealized loss on securities, net of taxes of $28.6				(43.2)	(43.2)
Net unrealized loss on hedging instruments, net of taxes of $31.7				(52.2)	(52.2)
Minimum pension liability, net of taxes of $77.2				(118.1)	(118.1)
Total Comprehensive Income			525.6	(384.1)	141.5
Common stock dividend declared ($0.96 per share)			(157.6)		(157.6)
Common stock issued	1,135	28.5			28.5
Other		8.2	(1.9)		6.3
Balance at December 31, 2002	164,843	2,078.9	1,977.6	(194.2)	3,862.3
Comprehensive Income					
Net income			277.3		277.3
Other comprehensive income					
Reclassification of net gain on sales of securities from OCI to net income, net of taxes of $0.2				(0.4)	(0.4)
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $10.7				(16.4)	(16.4)
Net unrealized gain on securities, net of taxes of $24.4				37.3	37.3
Net unrealized gain on hedging instruments, net of taxes of $15.8				39.9	39.9
Minimum pension liability, net of taxes of $8.2				12.6	12.6
Total Comprehensive Income			277.3	73.0	350.3
Common stock dividend declared ($1.04 per share)			(172.8)		(172.8)
Common stock issued	2,976	100.9			100.9
Other			(0.2)		(0.2)

				Accumulated Other Comprehensive Income (Loss)	
Balance at December 31, 2003	167,819	2,179.8	2,081.9	(121.2)	4,140.5
Comprehensive Income					
Net income			**539.7**		**539.7**
Other comprehensive income					
Reclassification of net loss on securities from OCI to net income, net of taxes of $1.4				**2.2**	**2.2**
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $169.0				**(270.8)**	**(270.8)**
Net unrealized gain on securities, net of taxes of $22.2				**33.7**	**33.7**
Net unrealized gain on hedging instruments, net of taxes of $124.7				**196.8**	**196.8**
Net unrealized gain on foreign currency translation				**0.4**	**0.4**
Minimum pension liability, net of taxes of $27.9				**(42.6)**	**(42.6)**
Total Comprehensive Income			**539.7**	**(80.3)**	**459.4**
Common stock dividend declared ($1.14 per share)			**(196.3)**		**(196.3)**
Common stock issued	**8,514**	**322.7**			**322.7**
Other			**0.6**		**0.6**
Balance at December 31, 2004	**176,333**	**$ 2,502.5**	**$ 2,425.9**	**$ (201.5)**	**$ 4,726.9**

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,

	2004	2003
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
7 7/8% Notes, due April 1, 2005	**$ 300.0**	$ 300.0
6.35% Fixed-Rate Notes, due April 1, 2007	**600.0**	600.0
6.125% Fixed-Rate Notes, due September 1, 2009	**500.0**	500.0
7.00% Fixed-Rate Notes, due April 1, 2012	**700.0**	700.0
4.55% Fixed-Rate Notes, due June 15, 2015	**550.0**	550.0
7.60% Fixed-Rate Notes, due April 1, 2032	**700.0**	700.0
Fair Value of Interest Rate Swaps	**13.3**	
Total long-term debt of Constellation Energy	**3,363.3**	3,350.0
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Pollution control loan, due July 1, 2011	**36.0**	36.0
Port facilities loan, due June 1, 2013	**48.0**	48.0
Adjustable rate pollution control loan, due July 1, 2014	**20.0**	20.0
5.55% Pollution control revenue refunding loan, due July 15, 2014	**47.0**	47.0
Economic development loan, due December 1, 2018	**35.0**	35.0
6.00% Pollution control revenue refunding loan, due April 1, 2024	**75.0**	75.0
Floating-rate pollution control loan, due June 1, 2027	**8.8**	8.8
District Cooling facilities loan, due December 1, 2031	**25.0**	25.0
Loans under revolving credit agreements	**100.1**	46.3
Geothermal facilities loan, due September 30, 2011		45.3
4.25% Mortgage note, due March 15, 2009	**2.3**	2.8
South Carolina synthetic fuel facility loan, due January 15, 2008	**40.0**	
Total long-term debt of nonregulated businesses	**437.2**	389.2
First Refunding Mortgage Bonds of BGE		
5 1/2% Series, due April 15, 2004		125.0
Remarketed floating-rate series, due September 1, 2006	**99.3**	104.1
7 1/2% Series, due January 15, 2007	**122.5**	122.5
6 5/8% Series, due March 15, 2008	**124.5**	124.5
Total First Refunding Mortgage Bonds of BGE	**346.3**	476.1
Other long-term debt of BGE		
5.25% Notes, due December 15, 2006	**300.0**	300.0
5.20% Notes, due June 15, 2033	**200.0**	200.0
Medium-term notes, Series B	**12.1**	12.1
Medium-term notes, Series D	**48.0**	68.0
Medium-term notes, Series E	**199.5**	199.5
Medium-term notes, Series G	**140.0**	140.0
Total other long-term debt of BGE	**899.6**	919.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7

At December 31,

		2004		2003
Unamortized discount and premium		**(10.5)**		(10.2)
Current portion of long-term debt		**(480.4)**		(343.2)
Total long-term debt	**$**	**4,813.2**	$	5,039.2

See Notes to Consolidated Financial Statements.

continued on next page

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Constellation Energy Group, Inc. and Subsidiaries

At December 31,

	2004	2003
	(In millions)	
Minority Interests	**$ 90.9**	$ 113.4
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized 7.125%, 1993 Series, 400,000 shares outstanding, callable at $103.21 per share until June 30, 2005, and at lesser amounts thereafter	**40.0**	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $103.14 per share until September 30, 2005, and at lesser amounts thereafter	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $103.02 per share until December 31, 2005, and at lesser amounts thereafter	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, not callable prior to October 1, 2005, then callable at $103.50 per share until September 30, 2006	**60.0**	60.0
Total preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 250,000,000 shares authorized; 176,333,121 and 167,819,338 shares issued and outstanding at December 31, 2004 and 2003, respectively. (At December 31, 2004, 5,884,607 shares were reserved for the long-term incentive plans, 7,957,620 shares were reserved for the Shareholder Investment Plan, 520,000 shares were reserved for the continuous offering programs, and 422,651 shares were reserved for the employee savings plan.)	**2,502.5**	2,179.8
Retained earnings	**2,425.9**	2,081.9
Accumulated other comprehensive loss	**(201.5)**	(121.2)
Total common shareholders' equity	**4,726.9**	4,140.5
Total Capitalization	**$ 9,821.0**	$ 9,483.1

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2004**	**2003**	**2002**
		(In millions)	
Revenues			
Electric revenues	**$ 1,967.7**	$ 1,921.6	$ 1,966.0
Gas revenues	**757.0**	726.0	581.3
Total revenues	**2,724.7**	2,647.6	2,547.3
Expenses			
Operating Expenses			
Electricity purchased for resale expenses	**1,034.0**	1,023.5	1,080.7
Gas purchased for resale	**484.3**	445.8	316.7
Operations and maintenance	**427.8**	406.2	366.6
Workforce reduction costs		0.7	35.3
Depreciation and amortization	**242.3**	228.3	221.6
Taxes other than income taxes	**164.9**	158.1	160.1
Total expenses	**2,353.3**	2,262.6	2,181.0
Income from Operations	**371.4**	385.0	366.3
Other (Expense) Income	**(6.4)**	(5.4)	10.7
Fixed Charges			
Interest expense	**97.3**	112.8	142.1
Allowance for borrowed funds used during construction	**(1.1)**	(1.6)	(1.5)
Total fixed charges	**96.2**	111.2	140.6
Income Before Income Taxes	**268.8**	268.4	236.4
Income Taxes			
Current	**69.4**	48.5	67.4
Deferred	**34.9**	58.5	28.0
Investment tax credit adjustments	**(1.8)**	(1.8)	(2.1)
Total income taxes	**102.5**	105.2	93.3
Net Income	**166.3**	163.2	143.1
Preference Stock Dividends	**13.2**	13.2	13.2
Earnings Applicable to Common Stock	**$ 153.1**	$ 150.0	$ 129.9

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2004**	**2003**	**2002**
		(In millions)	
Net Income	**$ 153.1**	$ 150.0	$ 129.9
Other comprehensive income			
	(0.1)		

Year Ended December 31,	2004	2003	2002
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $0.0			
Unrealized gain on hedging instruments, net of taxes of $0.4		0.8	
Comprehensive Income	**$ 153.0**	$ 150.8	$ 129.9

See Notes to Consolidated Financial Statements

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,

	2004	2003
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 8.2**	$ 11.0
Accounts receivable (net of allowance for uncollectibles of **$13.0** and $10.7, respectively)	**381.8**	354.8
Investment in cash pool, affiliated company	**127.9**	230.2
Accounts receivable, affiliated companies	**1.0**	4.5
Fuel stocks	**86.5**	62.8
Materials and supplies	**34.6**	29.9
Prepaid taxes other than income taxes	**44.5**	42.8
Other	**7.2**	9.9
Total current assets	**691.7**	745.9
Investments and Other Assets		
Regulatory assets (net)	**195.4**	229.5
Receivable, affiliated company	**150.4**	131.6
Other	**134.2**	140.6
Total investments and other assets	**480.0**	501.7
Utility Plant		
Plant in service		
Electric	**3,759.3**	3,599.3
Gas	**1,086.7**	1,064.7
Common	**478.4**	467.7
Total plant in service	**5,324.4**	5,131.7
Accumulated depreciation	**(1,921.5)**	(1,807.7)
Net plant in service	**3,402.9**	3,324.0
Construction work in progress	**83.1**	130.5
Plant held for future use	**5.2**	4.5
Net utility plant	**3,491.2**	3,459.0
Total Assets	**$ 4,662.9**	$ 4,706.6

See Notes to Consolidated Financial Statements.

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

CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,

	2004	2003
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Current portion of long-term debt	**$ 165.9**	$ 330.6
Accounts payable and accrued liabilities	**125.4**	101.2
Accounts payable and accrued liabilities, affiliated companies	**146.1**	151.7
Customer deposits	**64.3**	59.7
Accrued taxes	**32.2**	43.0
Accrued expenses and other	**71.7**	75.2
Total current liabilities	**605.6**	761.4
Deferred Credits and Other Liabilities		
Deferred income taxes	**608.0**	576.2
Postretirement and postemployment benefits	**278.2**	279.2
Deferred investment tax credits	**16.9**	18.7
Other	**20.0**	30.8
Total deferred credits and other liabilities	**923.1**	904.9
Long-term Debt		
First refunding mortgage bonds of BGE	**346.3**	476.1
Other long-term debt of BGE	**899.6**	919.6
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Long-term debt of nonregulated businesses	**25.0**	25.0
Unamortized discount and premium	**(3.2)**	(4.1)
Current portion of long-term debt	**(165.9)**	(330.6)
Total long-term debt	**1,359.5**	1,343.7
Minority Interest	**18.7**	18.9
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0
Common Shareholder's Equity		
Common stock	**912.2**	912.2
Retained earnings	**653.1**	574.7
Accumulated other comprehensive income	**0.7**	0.8
Total common shareholder's equity	**1,566.0**	1,487.7
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 4,662.9**	$ 4,706.6

At December 31,	**2004**	**2003**

See Notes to Consolidated Financial Statements.

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2004**	**2003**	**2002**
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ **166.3**	$ 163.2	$ 143.1
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**257.4**	242.7	234.4
Deferred income taxes	**34.9**	58.5	28.0
Investment tax credit adjustments	**(1.8)**	(1.8)	(2.1)
Deferred fuel costs	**6.0**	(10.1)	23.9
Pension and postemployment benefits	**(16.6)**	(56.2)	(40.7)
Allowance for equity funds used during construction	**(2.0)**	(3.0)	(2.8)
Workforce reduction costs		0.7	35.3
Changes in			
Accounts receivable	**(27.0)**	2.7	(62.3)
Receivables, affiliated companies	**3.5**	126.7	(67.8)
Materials, supplies, and fuel stocks	**(28.4)**	(20.3)	13.0
Other current assets	**1.0**	(0.4)	27.8
Accounts payable and accrued liabilities	**24.2**	8.0	39.6
Accounts payable and accrued liabilities, affiliated companies	**(5.6)**	66.1	(7.0)
Other current liabilities	**(10.3)**	14.0	(11.2)
Other	**(30.2)**	(22.9)	129.0
Net cash provided by operating activities	**371.4**	567.9	480.2
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(246.4)**	(269.0)	(202.5)
Change in cash pool at parent	**102.3**	107.9	101.0
Sales of investments and other assets	**4.9**		
Other	**2.7**	1.8	(17.0)
Net cash used in investing activities	**(136.5)**	(159.3)	(118.5)
Cash Flows From Financing Activities			
Proceeds from issuance of long-term debt		439.4	
Repayment of long-term debt	**(149.8)**	(710.4)	(575.5)
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Distribution (to) from parent	**(74.7)**	(124.8)	200.0
Other		1.2	(0.2)
Net cash used in financing activities	**(237.7)**	(407.8)	(388.9)
Net (Decrease) Increase in Cash and Cash Equivalents	**(2.8)**	0.8	(27.2)
Cash and Cash Equivalents at Beginning of Year	**11.0**	10.2	37.4
Cash and Cash Equivalents at End of Year	$ **8.2**	$ 11.0	$ 10.2
Other Cash Flow Information:			

Year Ended December 31,	**2004**	2003	2002
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 95.5**	$ 120.6	$ 147.5
Income taxes	**$ 80.7**	$ 24.7	$ 36.6

See Notes to Consolidated Financial Statements.

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

Notes to Consolidated Financial Statements

1 Significant Accounting Policies

Nature of Our Business

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). Our merchant energy business is a competitive provider of energy solutions for a variety of customers. BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in *Note 3*.

This report is a combined report of Constellation Energy and BGE. References in this report to "we" and "our" are to Constellation Energy and its subsidiaries. References in this report to the "regulated business(es)" are to BGE.

Consolidation Policy

We use three different accounting methods to report our investments in our subsidiaries or other companies: consolidation, the equity method, and the cost method.

Consolidation

We use consolidation for two types of entities:

- subsidiaries (other than variable interest entities) in which we own a majority of the voting stock, and
- variable interest entities (VIEs) for which we are the primary beneficiary. Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R, *Consolidation of Variable Interest Entities*, requires us to use consolidation when we are the primary beneficiary of a VIE, which means that we have a controlling financial interest in a VIE. We discuss FIN 46R in more detail later in this Note.

Consolidation means that we combine the accounts of these entities with our accounts. Therefore, our consolidated financial statements include our accounts, the accounts of our majority- owned subsidiaries that are not VIEs, and the accounts of VIEs for which we are the primary beneficiary. We have not consolidated any entities for which we do not have a controlling voting interest. We eliminate all intercompany balances and transactions when we consolidate these accounts.

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies (including qualifying facilities and power projects) where we hold a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Regulation of Electric and Gas Business

The Maryland Public Service Commission (Maryland PSC) and the Federal Energy Regulatory Commission (FERC) provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or the FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers.

When this happens, we must defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) certain regulated business expenses and income as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.*

We summarize and discuss our regulatory assets and liabilities further in *Note 6*.

Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

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

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

Reclassifications

We have reclassified certain prior-year amounts for comparative purposes. These reclassifications did not affect consolidated net income for the years presented.

Revenues

Nonregulated Businesses

We record revenues from the sale of energy, energy-related products, and energy services under the accrual method of accounting in the period when we deliver energy commodities or products, render services, or settle contracts. We use accrual accounting for our merchant energy and other nonregulated business transactions, including the generation or purchase and sale of electricity, gas, and coal as part of our physical delivery activities and for power, gas, and coal sales contracts that are not subject to mark-to-market accounting. Sales contracts that are eligible for accrual accounting include non-derivative transactions and derivatives that qualify for and are designated as normal purchases and normal sales of commodities that will be physically delivered. We record accrual revenues, including settlements with independent system operators, on a gross basis because we are a principal to the transaction and otherwise meet the requirements of Emerging Issues Task Force (EITF) 03-11, *Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes,* and EITF 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*.

We may make or receive cash payments at the time we assume a power sale agreement for which the contract price differs from current market prices. We recognize the cash payment at inception in our Consolidated Balance Sheets as an "Other current asset or liability" to the extent that performance under the contract is less than 12 months and as an "Other asset or liability" to the extent that performance under the contract is greater than 12 months. We amortize these assets and liabilities into revenues based on the expected cash flows provided by the contracts.

We record revenues using the mark-to-market method of accounting for derivative contracts for which we are not permitted to use accrual accounting or hedge accounting. We discuss our use of hedge accounting in the *Derivatives and Hedging Activities* section later in this Note. 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 these derivatives 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 revenues include:

- gains or losses on new transactions at origination to the extent permitted by applicable accounting rules,
- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

We record valuation adjustments to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market energy assets and liabilities. To the extent possible, we utilize market-based data together with quantitative methods for both measuring the uncertainties for which we record valuation adjustments and determining the level of such adjustments and changes in those levels.

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

- Close-out adjustment represents the estimated cost to close out or sell to a third-party open mark-to-market positions. This valuation adjustment has the effect of valuing "long" positions (the purchase of a commodity) at the bid price and "short" positions (the sale of a commodity) at the offer price. We compute this adjustment based on our estimate of the bid/offer spread for each commodity and option price and the absolute quantity of our net open positions for each year. The level of total close-out valuation adjustments 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. To the extent that we are not able to obtain observable market information for similar contracts, the close-out adjustment is equivalent to the initial contract margin, thereby recording no gain or loss at inception. In the absence of observable market information, there is a presumption that the transaction price is equal to the market value of the contract, and therefore we do not recognize a gain or loss at inception. We recognize such gains or losses in earnings as we realize cash flows under the contract or when observable market data becomes available.

Credit-spread adjustment for risk management purposes we compute the value of our mark-to-market energy 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 energy assets to reflect the credit-worthiness of each customer (counterparty) based upon either published credit ratings, where available, or equivalent internal credit ratings and associated default probability percentages. We compute this adjustment by applying the appropriate default probability percentage to our outstanding credit exposure, net of collateral, for each counterparty. The level of this adjustment 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.

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

During 2002, the FASB issued EITF 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 energy contracts. These changes included requiring the accrual method of accounting for energy contracts that are not derivatives and clarifying when gains or losses can be recognized at the inception of derivative contracts. 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 contracts that were subject to the requirements of EITF 02-3 were primarily our full requirements load-serving contracts and unit-contingent power purchase contracts, which are not derivatives. These contracts were entered into prior to our shift to accrual accounting earlier in 2002.

Certain transactions entered into under master agreements and other arrangements provide our merchant energy business with a right of setoff in the event of bankruptcy or default by the counterparty. We report such transactions net in our Consolidated Balance Sheets in accordance with FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts*.

We also include equity in earnings from our investments in qualifying facilities and power projects in "Nonregulated revenues" in our Consolidated Statements of Income.

Regulated Business

We record regulated revenues when we provide service to customers.

Fuel and Purchased Energy Expenses

We incur costs for:

- the fuel we use to generate electricity,
- purchases of electricity from others, and
- natural gas and coal that we resell.

These costs are included in "Fuel and purchased energy expenses" in our Consolidated Statements of Income. We discuss certain of these separately below. We also include certain non-fuel direct costs, such as ancillary services, transmission costs, and brokerage fees in "Fuel and purchased energy expenses" in our Consolidated Statements of Income.

Fuel Used to Generate Electricity and Purchases of Electricity From Others

We assemble a variety of power supply resources, including baseload, intermediate, and peaking plants that we own, as well as a variety of power supply contracts that may have similar characteristics, in order to enable us to meet our customers' energy requirements, which vary on an hourly basis. We purchase power when our load-serving requirements exceed the amount of power available from our supply resources or when it is more economic to do so than to operate our power plants. The amount of power purchased depends on a number of factors, including the capacity and availability of our power plants, the level of customer demand, and the relative economics of generating power versus purchasing power from the spot market.

We also have acquired contracts and certain power purchase agreements that qualify as operating leases. Under these operating leases, we are required to make fixed capacity payments, as well as variable payments based on the actual output of the plants. We may make or receive cash payments at the time we acquire a contract or assume a power purchase agreement when the contract price differs from current market prices. We recognize the cash payment at inception in our Consolidated Balance Sheets as an "Other current asset or liability" to the extent that performance under the contract is less than 12 months and as an "Other asset or liability" to the extent that performance under the contract is greater than 12 months. We amortize these assets and liabilities into fuel and purchased energy expenses based on the expected cash flows provided by the contracts.

BGE purchased from our wholesale marketing and risk management operation 100% of the energy and capacity required to meet its fixed-price standard offer service obligations through June 30, 2004. BGE purchases 100% of the energy and capacity required to meet its residential fixed-price standard offer service obligations through June 30, 2006 from our wholesale marketing and risk management operation.

BGE is obligated to provide market-based standard offer service to residential customers from July 1, 2006 through May 31, 2010, and for commercial and industrial customers for one, two, or four year periods beyond June 30, 2004, depending on customer load. The POLR rates charged during these time periods will recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a shareholder return component and an incremental cost component.

Bidding to supply BGE's standard offer service to commercial and industrial customers beyond June 30, 2004 occurred through a multi-round competitive bidding process in 2004. As a result, BGE executed one and two-year contracts for commercial and industrial electric power supply.

Regulated Natural Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses" set by the Maryland PSC. Under these clauses, BGE defers the difference between certain of its actual costs related to the gas commodity and what it collects from customers under the commodity charge in a given period. BGE either bills or refunds its customers the difference in the future. The Maryland PSC approved a modification of the gas cost adjustment clauses to provide a market-based rates incentive mechanism. Under the market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. Effective November 2001, the Maryland PSC approved an order that modifies certain provisions of the market-based rates incentive mechanism. These provisions require that BGE secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism.

Derivatives and 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 as discussed further in *Note 13*. In order to manage these risks, we use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future,
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date,
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity, and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

SFAS No. 133*, Accounting for Derivative Instruments and Hedging Activities,* as amended, requires that we recognize at fair value all derivatives not qualifying for accrual accounting under the normal purchase and normal sale exception. We record derivatives that are designated as hedges in "Risk management assets or liabilities" and derivatives not designated as hedges in "Mark-to-market energy assets or liabilities" in our Consolidated Balance Sheets.

We record changes in the value of derivatives that are not designated as cash-flow hedges in earnings during the period of change. We record changes in the fair value of derivatives designated as cash-flow hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we reclassify the amounts recorded in other comprehensive income into earnings. We record the ineffective portion of changes in the fair value of derivatives used as cash-flow hedges immediately in earnings.

We summarize our cash-flow hedging activities under SFAS No. 133 and the income statement classification of amounts reclassified from "Accumulated other comprehensive income (loss)" as follows:

Risk	Derivative	Income Statement Classification
Interest rate risk associated with new debt issuances	Interest rate swaps	Interest expense
Nonregulated energy sales	Futures and forward contracts	Nonregulated revenues
Nonregulated fuel and energy purchases	Futures and forward contracts	Fuel and purchased energy expenses

Risk	Derivative	Income Statement Classification
Nonregulated gas purchases for resale	Futures and forward contracts and price and basis swaps	Fuel and purchased energy expenses
Regulated gas purchases for resale	Price and basis swaps	Fuel and purchased energy expenses

We designate certain derivatives as fair value hedges. We record changes in the fair value of these derivatives and changes in the fair value of the hedged assets or liabilities in earnings as the changes occur. We summarize our fair value hedging activities and the income statement classification of changes in the fair value of these hedges and the related hedged items as follows:

Risk	Derivative	Income Statement Classification
Optimize mix of fixed and floating-rate debt	Interest rate swaps	Interest expense
Value of natural gas in storage	Forward contracts and price and basis swaps	Fuel and purchased energy expenses

We record changes in the fair value of interest rate swaps and the debt being hedged in "Risk management assets and liabilities" and "Long-term debt" and changes in the fair value of the gas being hedged and related derivatives in "Fuel stocks" and "Risk management assets and liabilities" in our Consolidated Balance Sheets. In addition, we record the difference between interest on hedged fixed-rate debt and floating-rate swaps in "Interest expense" in the periods that the swaps settle.

Credit Risk

Credit risk is the loss that may result from counterparty non-performance. We are exposed to credit risk, primarily through our merchant energy business. We use credit policies to manage our credit risk, including utilizing an established credit approval process, daily monitoring of counterparty limits, employing credit mitigation measures such as margin, collateral or prepayment arrangements, and using master netting agreements. We measure credit risk as the replacement cost for open energy commodity and derivative positions (both mark-to-market and accrual) plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, less any unrealized losses where we have a legally enforceable right of setoff.

Electric and gas utilities, cooperatives, and energy marketers comprise the majority of counterparties underlying our assets from our wholesale marketing and risk management activities. We held cash collateral from these counterparties totaling $145.9 million as of December 31, 2004 and $121.9 million as of December 31, 2003. These amounts are included in "Customer deposits and collateral" in our Consolidated Balance Sheets.

Taxes

We summarize our income taxes in *Note 10*. Our subsidiary income taxes are computed on a separate return basis. As you read this section, it may be helpful to refer to *Note 10*.

Income Tax Expense

We have two categories of income tax expense current and deferred. We describe each of these below:

- current income tax expense consists solely of regular tax less applicable tax credits, and
- deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to accumulated other comprehensive income. Our deferred income tax expense is increased or reduced for changes to the "Income taxes recoverable through future rates (net)" regulatory asset (described later in this Note) during the year.

Tax Credits

We have deferred the investment tax credits associated with our regulated business and assets previously held by our regulated business in our Consolidated Balance Sheets. The investment tax credits are amortized evenly to income over the life of each property. We reduce current income tax expense in our Consolidated Statements of Income for the investment tax credits and other tax credits associated with our nonregulated businesses.

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

Deferred Income Tax Assets and Liabilities

We must report some of our revenues and expenses differently for our financial statements than for income tax return purposes. The tax effects of the temporary differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the deferred income tax assets and liabilities using income tax rates that are currently in effect.

A portion of our total deferred income tax liability relates to our regulated business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as "Income taxes recoverable through future rates (net)." We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in *Note 6*.

State and Local Taxes

State and local income taxes are included in "Income taxes" in our Consolidated Statements of Income.

BGE also pays Maryland public service company franchise tax on distribution, and delivery of electricity and natural gas. We include the franchise tax in "Taxes other than income taxes" in our Consolidated Statements of Income.

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 year. 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 were 1.0 million in 2004 and 0.4 million in 2003 and consisted of stock options. There were no stock options excluded from the computation of diluted EPS for the year ended December 31, 2004. Stock options to purchase approximately 1.2 million shares in 2003 and approximately 4.1 million shares in 2002 were not dilutive and were excluded from the computation of diluted EPS for these respective years.

Stock-Based Compensation

Under our long-term incentive plans, we have granted stock options, performance-based units, performance and service-based restricted stock, and equity to officers, key employees, and members of the Board of Directors. We discuss this in more detail in *Note 14*.

As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*, we presently 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.

Our stock options are granted with an exercise price not less than the market value of the common stock at the date of grant. Accordingly, no compensation expense is recorded for these awards. However, when we grant options subject to a contingency, we recognize compensation expense when options granted have an exercise price less than the market value of the underlying common stock on the date the contingency is satisfied. We amortize compensation expense for restricted stock and stock units over the performance/service period, which is typically a one to five-year period.

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 year.

Year Ended December 31,	**2004**		**2003**		**2002**	
		(In millions, except per share amounts)				
Net income, as reported	**$**	**539.7**	$	277.3	$	525.6
Add: Stock-based compensation determined under intrinsic value method and included in reported net income, net of related tax effects		**13.2**		12.0		6.4
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of related tax effects		**(21.3)**		(20.7)		(17.1)
Pro-forma net income	**$**	**531.6**	$	268.6	$	514.9
Earnings per share:						
Basic as reported	**$**	**3.14**	$	1.67	$	3.20
Basic pro-forma	**$**	**3.09**	$	1.62	$	3.14
Diluted as reported	**$**	**3.12**	$	1.66	$	3.20
Diluted pro-forma	**$**	**3.07**	$	1.61	$	3.13

In the table above, the stock-based compensation expense included in reported net income, net of related tax effects is as follows:

- in 2004, $13.2 million after-tax, or $21.4 million pre-tax comprised of $1.0 million of pre-tax expense for certain stock options, $17.0 million for restricted stock, $2.9 million for performance-based units, and $0.5 million for equity grants,
- in 2003, $12.0 million after-tax, or $18.6 million pre-tax comprised of $1.8 million of pre-tax expense for certain stock options, $16.4 million for restricted stock, and $0.4 million for equity grants, and

in 2002, a $6.4 million after-tax, or $10.1 million pre-tax comprised of $3.0 million of pre-tax expense for certain stock options, $6.6 million for restricted stock, and $0.5 million for equity grants.

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

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents.

Accounts Receivable and Allowance for Uncollectibles

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectibles. We establish an allowance for uncollectibles based on our expected exposure to the credit risk of customers based on a variety of factors.

Materials, Supplies, and Fuel Stocks

We record our fuel stocks, emissions credits, coal held for resale, and materials and supplies at the lower of cost or market. We determine cost using the average cost method for all of our inventory other than our coal held for resale for which we use the specific identification method.

Real Estate Projects

In *Note 4*, we summarize the real estate projects that are in our Consolidated Balance Sheets. At December 31, 2004, the projects primarily consist of approximately 190 acres of land holdings in various stages of development located at 4 sites in the central Maryland region, including an operating waste water treatment plant located in Anne Arundel County, Maryland. The costs incurred to develop properties are included as part of the cost of the properties.

Financial Investments and Trading Securities

In *Note 4*, we summarize the financial investments that are in our Consolidated Balance Sheets.

SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* applies particular requirements to some of our investments in debt and equity securities. We report those investments at fair value, and we use either specific identification or average cost to determine their cost for computing realized gains or losses. We classify these investments as either trading securities or available-for-sale securities, which we describe separately below. We report investments that are not covered by SFAS No. 115 at their cost.

Trading Securities

In 2002, our other nonregulated businesses classified some of their investments in marketable equity securities and financial limited partnerships as trading securities. We included any unrealized gains or losses on these securities in "Nonregulated revenues" in our Consolidated Statements of Income. We no longer hold any investments classified as trading securities for which unrealized gains or losses are recognized in our Consolidated Statements of Income.

Available-for-Sale Securities

We classify our investments in the nuclear decommissioning trust funds as available-for-sale securities. We describe the nuclear decommissioning trusts and the related asset retirement obligations in the "Nuclear Decommissioning" section of this Note. In addition, we have investments in trust assets securing certain executive benefits that are classified as available-for-sale securities.

We include any unrealized gains or losses on our available-for-sale securities in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity and Comprehensive Income and Consolidated Statements of Capitalization.

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

Long-Lived Assets

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 requirements 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.

We determine if long-lived assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We would record an impairment loss if the undiscounted expected future cash flows from an asset were less than the carrying amount of the asset. We are also required to evaluate our equity-method and cost-method investments (for example, in partnerships that own power projects) for impairment. APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

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

Debt and Equity Securities

Our investments in debt and equity securities, which primarily consist of our nuclear decommissioning trust fund investments, are subject to impairment evaluations under SFAS No. 115, A*ccounting for Certain Investments in Debt and Equity Securities.* SFAS No. 115 requires us to determine whether a decline in fair value of an investment below the amortized cost basis is other than temporary. If we determine that the decline in fair value is judged to be other than temporary, the cost basis of the investment must be written down to fair value as a new cost basis. We discuss EITF 03-1, *The Meaning of Other Than Temporary Impairment and Its Application to Certain Investments,* in the *Accounting Standards Issued* section later in this note.

Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We account for goodwill and other intangibles under the provisions of SFAS No. 142, *Goodwill and Other Intangible Assets.* We do not amortize goodwill and certain other intangible assets. SFAS No. 142 requires us to evaluate goodwill and other intangibles for impairment at least annually or more frequently if events and circumstances indicate the business might be impaired. Goodwill is impaired if the carrying value of the business exceeds fair value. Annually, we estimate the fair value of the businesses we have acquired using techniques similar to those used to estimate future cash flows for long-lived assets as previously discussed. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. SFAS No. 142 also requires the amortization of intangible assets with finite lives. We discuss the changes in our intangible assets in more detail in *Note 5*.

Property, Plant and Equipment, Depreciation, Amortization, and Accretion of Asset Retirement Obligations

We report our property, plant and equipment at its original cost, unless impaired under the provisions of SFAS No. 144.

Our original costs include:

- material and labor,
- contractor costs, and
- construction overhead costs, financing costs, and costs for asset retirement obligations (where applicable).

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $191 million at December 31, 2004 and $189 million at December 31, 2003. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating expenses" in our Consolidated Statements of Income. Capital costs related to these plants are included in "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $206.4 million at December 31, 2004 and $184.4 million at December 31, 2003.

When we retire or dispose of property, plant and equipment, we remove the asset's cost from our Consolidated Balance Sheets. We charge this cost to accumulated depreciation for assets that were depreciated under the composite, straight-line method. This includes regulated property, plant and equipment and nonregulated generating assets transferred to our merchant energy business. For all other assets, we remove the accumulated depreciation and amortization amounts from our Consolidated Balance Sheets and record any gain or loss in our Consolidated Statements of Income.

The costs of maintenance and certain replacements are charged to "Operating expenses" in our Consolidated Statements of Income as incurred.

Depreciation Expense

We compute depreciation for our generating, electric transmission and distribution, and gas facilities over the estimated useful lives of depreciable property using the following methods:

- the composite, straight-line rates method, approved by the Maryland PSC, applied to the average investment, adjusted for anticipated costs of removal less salvage, in classes of depreciable property based on an average rate of approximately 3.5% per year for our regulated business,
- the composite, straight-line rates applied to the average investment, in classes of depreciable property based on an average rate of approximately 2.5% per year for the generating assets transferred from BGE to our merchant energy business, or

the modified units of production method (greater of straight-line method or units of production method) for other generating assets.

Other assets are depreciated using the straight-line method and the following estimated useful lives:

Asset	**Estimated Useful Lives**
Building and improvements	20 - 50 years
Office equipment and furniture	3 - 20 years
Transportation equipment	5 - 15 years
Computer software	3 - 10 years

Amortization Expense

Amortization is an accounting process of reducing an amount in our Consolidated Balance Sheets over a period of time that approximates the useful life of the related item. When we reduce amounts in our Consolidated Balance Sheets, we increase amortization expense in our Consolidated Statements of Income.

Accretion Expense

SFAS No. 143, *Accounting for Asset Retirement Obligations* provides the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets. At December 31, 2004, $821.8 million of our total asset retirement obligation of $825.0 million was associated with our nuclear power plants Calvert Cliffs, Nine Mile Point, and Ginna. We have also recorded asset retirement obligations associated with our other generating facilities and certain other long-lived assets. We record a liability when we are able to reasonably estimate the fair value of any future legal obligations associated with retirement that have been incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income until the settlement of the liability. We record a gain or loss when the liability is settled after retirement.

The change in our "Asset retirement obligations" liability during 2004 was as follows:

		(In millions)
Liability at January 1, 2004	$	595.9
Liabilities incurred		177.9
Liabilities settled		
Accretion expense		53.2
Other		(2.0)
Revisions to cash flows		
Liability at December 31, 2004	$	825.0

"Liabilities incurred" in the table above primarily reflect the asset retirement obligation recorded in connection with our acquisition of the R.E. Ginna Nuclear Power Plant (Ginna). We discuss the acquisition of Ginna in more detail in *Note 15*. "Other" in the table above represents the asset retirement obligation associated with our geothermal facility in Hawaii that was sold in the quarter ended June 2004. At the time of the sale, the asset retirement obligation was transferred to the buyer of the geothermal facility. We discuss the sale of the geothermal facility in more detail in *Note 2*.

Nuclear Fuel

We amortize nuclear fuel based on the energy produced over the life of the fuel including the quarterly fees we pay to the Department of Energy for the future disposal of spent nuclear fuel. These fees are based on the kilowatt-hours of electricity sold. We report the amortization expense for nuclear fuel in "Fuel and purchased energy expenses" in our Consolidated Statements of Income.

Nuclear Decommissioning

Effective January 1, 2003, we began to record decommissioning expense for Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) in accordance with SFAS No. 143 *Accounting for Asset Retirement Obligations* (SFAS 143). The "Asset retirement obligations" liability associated with the decommissioning of Calvert Cliffs was $286.1 million at December 31, 2004 and $265.5 million at December 31, 2003. Our contributions to the nuclear decommissioning trust funds for Calvert Cliffs were $22.0 million for 2004, $13.2 million for 2003 and $17.6 million for 2002. Under the Maryland PSC's order deregulating electric generation, BGE's customers must pay a total of $520 million in 1993 dollars, adjusted for inflation, to decommission Calvert Cliffs. BGE is collecting this amount on behalf of and passing it to Calvert Cliffs Nuclear Power Plant, Inc. Calvert Cliffs Nuclear Power Plant, Inc. is responsible for any difference between this amount and the actual costs to decommission the plant.

We began to record decommissioning expense for Nine Mile Point Nuclear Station (Nine Mile Point) in accordance with SFAS No. 143 on January 1, 2003. The "Asset retirement obligations" liability associated with the decommissioning was $351.5 million at December 31, 2004 and $326.2 million at December 31, 2003. We determined that the decommissioning trust funds established for Nine Mile Point are adequately funded to cover the future costs to decommission the plant and as such, no contributions were made to the trust funds during the years ended December 31, 2004, 2003, and 2002.

Upon the closing of the Ginna acquisition in 2004, the seller transferred $200.8 million in decommissioning funds. In return, we assumed all liability for the costs to decommission the unit. We believe that this transfer will be sufficient to cover the future costs to decommission the plant and as such, no contributions were made to the trust funds during the year ended December 31, 2004. Effective June 2004, we began to record decommissioning expense for Ginna in accordance with SFAS No. 143. The "Asset retirement obligations" liability associated with the decommissioning was $184.2 million at December 31, 2004. We discuss the acquisition of Ginna in more detail in *Note 15*.

In accordance with Nuclear Regulatory Commission (NRC) regulations, we maintain external decommissioning trusts to fund the costs expected to be incurred to decommission Calvert Cliffs, Nine Mile Point and Ginna. The NRC requires utilities to provide financial assurance that they will accumulate sufficient funds to pay for the cost of nuclear decommissioning. The assets in the trusts are reported in "Nuclear decommissioning trust funds" in our Consolidated Balance Sheets. These amounts are legally restricted for funding the costs of decommissioning. We classify the investments in the nuclear decommissioning trust funds as available-for-sale securities, and we report these investments at fair value in our Consolidated Balance Sheets as previously discussed in this Note. Investments by nuclear decommissioning trust funds are guided by the "prudent man" investment principle. The funds are prohibited from investing directly in Constellation Energy or its affiliates and any other entity owning a nuclear power plant.

As the owner of Calvert Cliffs, we are required, along with other domestic utilities, by the Energy Policy Act of 1992 to make contributions to a fund for decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. The contributions are paid by BGE and generally payable over 15 years with escalation for inflation and are based upon the proportionate amount of uranium enriched by the Department of Energy for each utility. BGE amortizes the deferred costs of decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. The previous owners retained the obligation for Nine Mile Point and Ginna.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

Our nonregulated businesses capitalize interest costs under SFAS No. 34, *Capitalizing Interest Costs,* for costs incurred to finance our power plant construction projects, real estate developed for internal use, and other capital projects.

Allowance for Funds Used During Construction (AFC)

BGE finances its construction projects with borrowed funds and equity funds. BGE is allowed by the Maryland PSC to record the costs of these funds as part of the cost of construction projects in its Consolidated Balance Sheets. BGE does this through the AFC, which it calculates using rates authorized by the Maryland PSC. BGE bills its customers for the AFC plus a return after the utility property is placed in service.

The AFC rates are 9.4% for electric plant, 8.6% for gas plant, and 9.2% for common plant. BGE compounds AFC annually.

Long-Term Debt

We defer all costs related to the issuance of long-term debt. These costs include underwriters' commissions, discounts or premiums, other costs such as legal, accounting, and regulatory fees, and printing costs. We amortize these costs into interest expense over the life of the debt.

When BGE incurs gains or losses on debt that it retires prior to maturity, it amortizes those gains or losses over the remaining original life of the debt.

Accounting Standards Issued

SFAS 123 Revised

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

We plan to adopt SFAS No. 123R effective July 1, 2005 using the Modified Prospective Application method without restatement of prior interim periods. Under this method, we will begin to amortize compensation cost for the remaining portion of our outstanding awards on the adoption date for which the requisite service has not yet been rendered. Compensation cost for these awards will be based on the fair value of those awards as disclosed on a pro-forma basis under SFAS 123 in the *Stock-Based Compensation* section of this note. We will account for awards that are granted, modified, or settled after the adoption date in accordance with SFAS No. 123R.

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

EITF 03-1

In March 2004, the EITF reached a consensus on Issue 03-1, *The Meaning of Other Than Temporary Impairment and Its Application to Certain Investments,* related to measurement and recognition criteria that would have become effective July 1, 2004. In accordance with Nuclear Regulatory Commission regulations, we do not manage the day-to-day activities of our nuclear decommissioning trust funds. As a result, a strict interpretation of EITF 03-1 would indicate that we do not have the ability and intent to hold investments whose market value is less than our cost until recovery.

In September 2004, the FASB issued FSP EITF 03-1-1 which delayed the implementation of the measurement and recognition criteria until additional implementation guidance could be developed. If relief from the strict interpretation previously discussed is not included in the pending FASB implementation guidance, we would be required to record into earnings any decline in market value below the cost of our nuclear decommissioning investments. If this interpretation of EITF 03-1 had become effective at December 31, 2004, we would have been required to record a pre-tax charge of approximately $2.8 million. We have approximately $1 billion invested in nuclear decommissioning trust assets. Therefore, a one percent decline in all of our investments below book value would result in approximately a $10 million pre-tax charge. We cannot predict the outcome of the implementation guidance. However, the impact could be material to our financial results.

Accounting Standards Adopted

FSP 106-2

In May 2004, FASB Staff Position (FSP) 106-2 was issued, which addresses accounting and disclosure requirements pertaining to the Medicare Prescription Drug Improvement and Modernization Act of 2003. FSP 106-2 is effective July 1, 2004. We discuss the impacts of the Medicare Prescription Drug Improvement and Modernization Act of 2003 recorded in accordance with FSP 106-2 in *Note 7*.

FSP 109-2

In the fourth quarter of 2004, the President signed into law the American Jobs Creation Act of 2004 (the Act) that provides a temporary incentive for U. S. multinational companies to repatriate foreign earnings. The temporary incentive for U. S. companies to repatriate accumulated foreign earnings provides an elective, 85 percent dividends received deduction for certain dividends from controlled foreign corporations that will be reinvested in the United States.

In response to the issuance of the Act, in December 2004, the FASB issued FSP No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004*. FSP No. 109-2 provides companies with additional time to evaluate the impact of the Act and provides accounting and disclosure guidance for applying the foreign earnings repatriation provisions of the Act. In December 2004, we repatriated $15 million in the form of a dividend from our Panamanian distribution facility, which we plan to reinvest in the United States to take advantage of the dividends received deduction. Since we previously provided federal deferred income taxes on the earnings of our foreign subsidiary that issued the dividend, in 2004 we recorded a net reduction of $4.4 million in federal tax expense in connection with the earnings repatriation.

FIN 46/FIN 46R

In January 2003, the FASB issued FIN 46, *Consolidation of Variable Interest Entities*, which was subsequently revised in its entirety with the issuance of FIN 46R in December 2003.

FIN 46R establishes conditions under which an entity must 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 46R if it does not have an equity investment sufficient for it to finance its activities without assistance from variable interest holders or if its equity investors lack any of the following characteristics of a controlling financial interest:

- control through voting rights,
- obligation to absorb expected losses, or
- right to receive expected residual returns.

FIN 46R requires us to consolidate VIEs for which we are the primary beneficiary and to disclose certain information about significant variable interests we hold. The primary beneficiary of a VIE is the entity that receives the majority of a VIE's expected losses, expected residual returns, or both.

FIN 46R was effective March 31, 2004, for all VIEs except special purpose entities (SPEs), for which the effective date was December 31, 2003. Therefore, at December 31, 2003, we and BGE deconsolidated BGE Capital Trust II, an SPE established to issue trust preferred securities as described in *Note 9*, because BGE is not its primary beneficiary. As a result, we currently record $257.7 million of deferrable interest subordinated debentures due to BGE Capital Trust II, and $7.7 million equity investment in BGE Capital Trust II in "Other assets" in our and BGE's Consolidated Balance Sheets.

As a result of adopting the remainder of the provisions of FIN 46R as of March 31, 2004, we were not required to consolidate or deconsolidate any non-SPE entities with which we are involved through variable interests. We had preliminarily determined that we were the primary beneficiary for an unconsolidated investment in a hydroelectric generating plant located in Pennsylvania because our two-thirds interest in the plant's earnings are disproportionate to our 50% voting interest. However, we subsequently determined that the entity is not a VIE because less than substantially all of the plant's activities are conducted on our behalf, and therefore we do not have to consolidate the entity.

We have a significant interest in the following VIEs for which we are not the primary beneficiary:

VIE	Nature of Involvement	Date of Involvement
Power projects and fuel supply entities	Equity investment and guarantees	Prior to 2003
Natural gas producing facility	Volumetric and price swap	July 2003

The following is summary information about these entities as of December 31, 2004:

	(In millions)
Total assets	$ 291.1
Total liabilities	147.0
Our ownership interest	41.1
Other ownership interests	103.0
Our maximum exposure to loss	75.3

The maximum exposure to loss represents the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of December 31, 2004 consists of the following:

- the carrying amount of our investment totaling $41.1 million,
- debt and performance guarantees totaling $13.4 million, and
- volumetric and price variability of up to $20.8 million associated with a natural gas producer swap, based on contract volumes and gas prices as of December 31, 2004.

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

2 Workforce Reduction, Impairment Losses, and Other Events

2004 Events

	Pre-Tax	After-Tax
	(In millions)	
Loss from discontinued operations	$ **(75.6)**	$ **(49.1)**
Recognition of 2003 synthetic fuel tax credits		**35.9**
Workforce reduction costs	**(9.7)**	**(5.9)**
Impairment losses and other costs	**(3.7)**	**(2.2)**
Net loss on sales of investments and other assets	**(1.2)**	**(0.6)**
Total special items	$ **(90.2)**	$ **(21.9)**

Loss from Discontinued Operations

In the fourth quarter of 2003, we began to re-evaluate our strategy regarding our geothermal generating facility in Hawaii. The reevaluation of our strategy included soliciting bids to determine the level of interest in the facility. As of December 31, 2003, management determined that disposal of the facility was more likely than not to occur. As a result, we evaluated the facility for impairment as of December 31, 2003, in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* and determined that the facility was not impaired primarily due to indicative bids from third parties above the carrying value of the assets.

In March 2004, after reviewing final binding offers, management committed to a plan to sell the facility that met the "held for sale" criteria under SFAS No. 144. Under SFAS No. 144, we record assets and liabilities held for sale at the lesser of the carrying amount or fair value less cost to sell.

The fair value of the facility as of March 31, 2004, based on the bids under consideration, was below carrying value. Therefore, we recorded a $71.6 million pre-tax, or $47.3 million after-tax, impairment charge during the first quarter of 2004. We reported the after-tax impairment charge as a component of "Loss from discontinued operations" in our Consolidated Statements of Income. Additionally, we recognized $1.5 million pre-tax, or $1.0 million after-tax, of earnings from the facility for the quarter ended March 31, 2004 as a component of

"Loss from discontinued operations."

In June 2004, we completed the sale of the facility. Based on the final sales price and other costs incurred over the remainder of the year, we recognized an additional loss of $5.5 million pre-tax, or $2.8 million after-tax. The sale of this facility was reflected in our merchant energy business reportable segment. In addition, as a result of a current audit relating to prior tax years for this facility, we could record additional gain or loss from discontinued operations in future periods.

We have not reclassified the prior year results of operations, which were reported under the equity method as "Nonregulated revenues," based on the immateriality of the amounts involved. The facility had a $4.0 million net loss, including a $1.1 million cumulative effect of change in accounting principle for the adoption of SFAS No. 143, during 2003.

Synthetic Fuel Tax Credits

In 2003, we purchased 99% ownership in a South Carolina facility that produces synthetic fuel. We did not recognize in our Consolidated Statements of Income the tax benefit of $35.9 million for credits claimed on our South Carolina facility in 2003 pending receipt of a favorable private letter ruling. In April 2004, we received a favorable private letter ruling. We believe receipt of the private letter ruling provides assurance that it is highly probable that the credits will be sustained. Therefore, we recognized the tax benefit of $35.9 million in our Consolidated Statements of Income in 2004. We discuss the synthetic fuel tax credits in more detail in *Note 10.*

Workforce Reduction Costs

In the fourth quarter of 2004, we approved a restructuring of the work forces of the Nine Mile Point and Calvert Cliffs nuclear generating stations that was effective in January 2005. In connection with this restructuring, approximately 108 employees will receive severance and other benefits under our existing benefit programs. At December 31, 2004, we accrued the estimated total cost of this reduction in workforce of $9.7 million pre-tax, or $5.9 million after-tax, in accordance with applicable accounting requirements.

Impairment of Financial Investment

Our other nonregulated businesses recognized a pre-tax impairment loss of $3.7 million, or $2.2 million after-tax, during the year ended December 31, 2004 related to an other than temporary decline in fair value of certain financial investments.

Net Loss on Sales of Investments and Other Assets

Our other nonregulated businesses recognized a pre-tax loss of $1.2 million, or $0.6 million after-tax, during the year ended December 31, 2004 on the sale of non-core assets as follows:

- a $1.1 million pre-tax gain in the first quarter on an installment sale of real estate,
- a $0.4 million pre-tax gain in the first quarter on the sale of a financial investment,
- a $3.3 million pre-tax gain in the second quarter on the sale of a financial investment,
- a $1.1 million pre-tax gain in the second quarter on the sale of real estate,
- a $7.5 million pre-tax loss in the third quarter on the sale of a financial investment, and
- a $0.4 million pre-tax gain in the fourth quarter on the sale of a financial investment.

2003 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs	$ (2.1)	$ (1.3)
Reduction of financial investment	(0.6)	(0.4)
Net gain on sales of investments and other assets	26.2	16.4
Total special items	$ 23.5	$ 14.7

Workforce Reduction Costs

During 2003, we recorded $2.1 million in pre-tax expense, or $1.3 million after-tax, of which BGE recorded $0.7 million pre-tax, associated with deferred payments to employees eligible for the 2001 Voluntary Special Early Retirement Program.

In 2004, we completed the 2002 workforce reduction programs. As a result, no involuntary severance liability was 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),* at December 31, 2004.

Impairment Losses and Other Costs

In 2003, our other nonregulated businesses recognized an impairment loss of $0.6 million pre-tax, or $0.4 million after-tax, related to the decline in value of our investment in an airplane.

Net Gain on Sales of Investments and Other Assets

During 2003, our other nonregulated businesses recognized $26.2 million of pre-tax, or $16.4 million after-tax, gains on the sales of non-core assets as follows:

- a $13.1 million pre-tax gain on the sale of certain real estate,
- 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 $0.6 million pre-tax gain on the sale of financial investments.

Hurricane Isabel

In September 2003, Hurricane Isabel caused damage to the electric and gas distribution system of BGE. As a result, BGE incurred capitalized costs of $32.0 million and maintenance expenses of $36.8 million, or $22.2 million after-tax to restore its distribution system. The maintenance expenses included $32.1 million pre-tax, or $19.4 million after-tax, of incremental expenses.

2002 Events

	Pre-Tax	After-Tax
	(In millions)	
Workforce reduction costs:		
Costs associated with 2001 programs	$ (50.8)	$ (30.8)
Costs associated with programs initiated in 2002	(12.0)	(7.2)
Total workforce reduction costs	(62.8)	(38.0)
Impairment losses and other costs:		
Impairments of investments in qualifying facilities and power projects	(14.4)	(9.9)
Costs associated with exit of BGE Home merchandise stores	(9.0)	(6.1)
Impairments of real estate and international investments	(1.8)	(1.2)
Total impairment losses and other costs	(25.2)	(17.2)
Net gain on sales of investments and other assets	261.3	166.7
Total special items	$ 173.3	$ 111.5

Workforce Reduction Costs

During 2002, we incurred costs related to workforce reduction efforts initiated in the fourth quarter of 2001 as discussed in this note and additional initiatives undertaken in the third quarter of 2002. We discuss these costs in more detail below.

Costs associated with 2001 Programs

In 2002, we recorded $63.7 million of net workforce reduction costs associated with our 2001 workforce reduction initiatives as discussed below. The $63.7 million included $50.8 million recognized as expense, of which BGE recognized $33.8 million. The remaining $12.9 million was recognized by BGE as a regulatory asset related to its gas business as discussed in *Note 6*.

We recorded $52.9 million when 308 employees elected the age 50 to 54 Voluntary Special Early Retirement Program (VSERP).

We reversed $17.8 million of the $25.1 million involuntary severance accrual that was recorded in 2001 to reflect the employees that elected the age 50 to 54 VSERP. Ultimately, we involuntarily severed 129 employees that resulted in a total cost for the involuntary severance program of $7.3 million.

We recorded $29.6 million of settlement charges related to our pension plans under SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*. These charges reflect the recognition of actuarial gains and losses associated with employees who have retired and taken their pension in the form of a lump-sum payment. Under SFAS No. 88, the settlement charge could not be recognized until lump-sum pension payments exceeded annual pension plan service and interest cost, which occurred in 2002.

We recorded a $1.6 million expense associated with deferred payments to employees eligible for the VSERP.

Partially offsetting these costs, we reversed approximately $2.6 million of previously accrued workforce reduction costs primarily as a result of the reversal of education and outplacement assistance benefits we accrued that employees did not utilize to the extent expected.

In 2002, we completed the 2001 workforce reduction programs. Accordingly, no involuntary severance liability recorded under EITF 94-3 remained at December 31, 2002.

Costs associated with 2002 Programs

In 2002, we recorded $12.0 million of expenses for anticipated involuntary severance costs in accordance with EITF 94-3 associated with new workforce reduction initiatives as follows:

We recorded $8.5 million for workforce reduction costs for the severance of 120 employees at Calvert Cliffs Nuclear Power Plant (Calvert Cliffs).

We recorded $1.6 million of workforce reduction costs for the severance of 27 employees in our information technology organization. BGE recorded $0.6 million of this amount.

We recorded $1.9 million of workforce reduction costs for the severance of 20 employees in our legal organization. BGE recorded $0.9 million of this amount.

At December 31, 2002, the involuntary severance liability recorded under EITF 94-3 for our 2002 workforce reduction programs was $12.0 million.

Impairment Losses and Other Costs

Investments in Qualifying Facilities and Power Projects

In the third quarter of 2002, our merchant energy business recorded impairment losses on certain of the investments in qualifying facilities and power projects totaling $14.4 million under the provisions of APB No. 18. We describe these investments in *Note 4*. The provisions of APB No. 18 require that an impairment loss be recognized when an investment experiences a loss in value that is other than temporary as discussed in *Note 1*.

During the third quarter of 2002, we performed an analysis of whether any of the investments were impaired. As a result of our analysis, we concluded that the declines in value of particular investments in certain qualifying facilities and power projects were other than temporary in nature under the provisions of APB No. 18 and we recognized the following losses in 2002:

- We recognized a $5.2 million other than temporary decline in value of our investment in a partnership that owns a geothermal project in Nevada. This project experienced a well implosion and we believe that the expected cash flows from the project will not be sufficient to recover our equity interest in that partnership.
- We recognized a $2.6 million other than temporary decline in value of our investment in a fuel processing site in Pennsylvania where the expected cash flows from a sublease are no longer expected to be sufficient to recover our lease costs associated with this site.
- We recognized a $6.6 million other than temporary decline in value of our investment in a partnership that owns a waste burning power project in Michigan. In 2001, we recognized a $6.1 million pre-tax impairment loss on this investment because we expected operating cash flows would not be sufficient to pay existing debt service and that we would not be able to recover our equity investment. However, at that time, we believed that we would recover our senior working capital loans receivable and accounts receivable for operating the project. As of the third quarter of 2002, the operating performance of the project did not improve as expected, and we believed the expected future cash flows were no longer sufficient to recover these receivables. Therefore, we recognized an additional impairment loss on this investment.

<u>*Closing of BGE Home Retail Merchandise Stores*</u>

In September 2002, we announced our decision to close our BGE Home retail merchandise stores. In connection with that decision, we recognized $9.5 million in exit costs. We recognized $2.9 million related to expected severance costs for 93 employees and $2.9 million of costs in connection with the termination of leases for the eight stores and other exit costs in accordance with EITF 94-3.

We also recognized $3.2 million for the write-off of unamortized leasehold improvements in accordance with SFAS No. 144, and $0.5 million for the write-down of inventory to a lower-of-cost-or-market valuation in accordance with Accounting Research Bulletin No. 43, *Restatement and Revision of Accounting Research Bulletins*. The $0.5 million is included in "Operating expenses" in our Consolidated Statements of Income.

<u>*Real Estate and International Investments*</u>

We changed our strategy from an intent to hold to an intent to sell for certain of our non-core assets in 2001. During 2002, we determined that the fair value of several real estate projects and our investment in a South American generation project declined below their respective book values due to deteriorating market conditions for these projects. Accordingly, we recorded losses that totaled $1.8 million for these projects in accordance with SFAS No. 144 and APB No. 18.

Net Gain on Sales of Investments and Other Assets

In February 2002, Reliant Resources, Inc. acquired all of the outstanding shares of Orion Power Holdings, Inc. (Orion) for $26.80 per share, including the shares we owned of Orion. We received cash proceeds of $454.1 million and recognized a gain of $255.5 million on the sale of our investment.

In the fourth quarter of 2001, we announced our decision to focus efforts and capital on core domestic energy businesses and undertook a plan to sell a number of non-core businesses and investments. In 2002, we made further progress on this initiative, and recognized approximately $5.8 million in net gains from the sale of several non-core assets including:

- Our other nonregulated businesses recognized gains totaling $6.7 million on the sale of several parcels of real estate and financial investments.
- In October 2002, we sold all of our 18 senior-living facilities for $77.2 million that represents a combination of cash and the assumption by the buyer of existing mortgages. Our other nonregulated businesses recognized a $2.8 million gain on the sale of our entire ownership interest in these facilities.
- Our merchant energy business recognized a $2.3 million gain on the sale of a discontinued wind-powered development project.

In 2001, our merchant energy business recognized an impairment loss on four turbines, associated with a discontinued development program. Since that time, many other companies canceled development projects and the market values for turbines have declined significantly. Orders for three of the four turbines were canceled with termination fees paid to the manufacturer consistent with the amount recognized in December 2001. The fourth turbine-generator set was sold during 2002 for $6.0 million below its book value.

3 Information by Operating Segment

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

- Our nonregulated merchant energy business includes:
  - full requirements load-serving sales of energy and capacity to utilities and commercial and industrial customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs),
  - gas retail energy products and services to commercial and industrial customers,
  - fossil, nuclear, and hydroelectric generating facilities and interests in qualifying facilities, fuel processing facilities, and power projects in the United States,
  - coal sourcing services for the variable or fixed supply needs of North American and international power generators, and
  - operations and maintenance consulting services.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in Maryland.

Our remaining nonregulated businesses:

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

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

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

	Reportable Segments					
	Merchant Energy Business	**Regulated Electric Business**	**Regulated Gas Business**	**Other Nonregulated Businesses**	**Eliminations**	**Consolidated**
				(In millions)		
2004						
Unaffiliated revenues	**$ 9,405.3**	**$ 1,967.6**	**$ 755.0**	**$ 421.8**	**$**	**$ 12,549.7**
Intersegment revenues	**984.6**	**0.1**	**2.0**	**0.2**	**(986.9)**	
Total revenues	**10,389.9**	**1,967.7**	**757.0**	**422.0**	**(986.9)**	**12,549.7**
Depreciation and amortization	**248.0**	**194.2**	**48.1**	**35.2**		**525.5**
Fixed charges	**196.2**	**80.3**	**29.1**	**24.7**		**330.3**
Income tax expense	**69.2**	**86.8**	**15.9**	**0.3**		**172.2**
Loss on discontinued operations	**(49.1)**					**(49.1)**
Net income (loss) (a)	**389.9**	**131.1**	**22.2**	**(3.5)**		**539.7**
Segment assets	**12,395.6**	**3,402.2**	**1,163.4**	**675.7**	**(289.8)**	**17,347.1**
Capital expenditures	**455.0**	**209.0**	**56.0**	**42.0**		**762.0**
2003						
Unaffiliated revenues	$ 6,465.9	$ 1,921.5	$ 712.7	$ 587.7	$	$ 9,687.8
Intersegment revenues	1,167.0	0.1	13.3	0.2	(1,180.6)	
Total revenues	7,632.9	1,921.6	726.0	587.9	(1,180.6)	9,687.8
Depreciation and amortization	229.5	181.7	46.6	21.2		479.0
Fixed charges	191.9	96.8	28.2	21.0	2.3	340.2
Income tax expense	146.9	73.5	32.0	17.1		269.5
Cumulative effects of changes in accounting principles	(198.4)					(198.4)
Net income (b)	114.6	107.5	43.0	12.2		277.3
Segment assets	10,503.7	3,512.0	1,069.1	778.7	(270.5)	15,593.0
Capital expenditures	419.0	236.0	53.0	53.0		761.0
2002						
Unaffiliated revenues	$ 1,645.1	$ 1,965.6	$ 570.5	$ 537.4	$	$ 4,718.6
Intersegment revenues	1,136.2	0.4	10.8		(1,147.4)	
Total revenues	2,781.3	1,966.0	581.3	537.4	(1,147.4)	4,718.6
Depreciation and amortization	242.8	174.2	47.4	16.6		481.0
Fixed charges	102.0	128.4	25.9	25.2		281.5
Income tax expense	127.2	70.6	23.0	88.8		309.6
Net income (c)	247.2	99.3	31.1	148.0		525.6
Segment assets	9,680.4	3,565.1	1,140.4	913.0	(355.6)	14,943.3
Capital expenditures	641.0	167.0	50.0	65.0		923.0

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

(a)

Our merchant energy business and our other nonregulated businesses recognized after-tax charges (income) of ($30.0 million) and $2.8 million, respectively, for recognition of 2003 synthetic fuel tax credits, workforce reduction costs, impairment losses and other costs, and net losses on sales of investments and other assets as described in more detail in Note 2.

(b)

Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges (income) of $0.7 million, $0.4 million, $0.1 million, and ($15.9 million), respectively, for workforce reduction costs, impairment losses and other costs, and net gains on sales of investments and other assets as described in more detail *in Note 2.*

(c) *Our merchant energy business, our regulated electric business, our regulated gas business, and our other nonregulated businesses recognized after-tax charges (income) of $28.3 million, $20.5 million, $0.8 million, and ($161.1 million), respectively, for workforce reduction costs, business exit costs, impairment losses and other costs, and net gains on sales of investments and other assets as described in more detail in Note 2.*

4 Investments

Real Estate Projects

Real estate projects recorded in "Other assets" were $28.8 million at December 31, 2004 and $44.3 million at December 31, 2003.

Investments in Qualifying Facilities and Power Projects

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

Investments in qualifying facilities and domestic power projects held by our merchant energy business consist of the following:

At December 31,	2004	2003
	(In millions)	
Coal	$ **128.7**	$ 130.5
Hydroelectric	**55.8**	57.3
Geothermal	**46.3**	56.0
Biomass	**50.2**	51.4
Fuel Processing	**22.5**	22.5
Solar	**10.4**	10.5
Total	$ **313.9**	$ 328.2

The investment in qualifying facilities and domestic power projects were accounted for under the following methods:

At December 31,	2004	2003
	(In millions)	
Equity method	$ **303.5**	$ 317.6
Cost method	**10.4**	10.6
Total power projects	$ **313.9**	$ 328.2

Our percentage voting interest in qualifying facilities and domestic power projects accounted for under the equity method ranges from 16% to 50%. Equity in earnings of these power projects were $18.0 million in 2004, $2.1 million in 2003, and $9.1 million in 2002.

Our power projects include investments of $240.2 million in 2004 and $251.8 million in 2003 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements.

Our other nonregulated businesses also held international energy projects accounted for under the equity method of $4.5 million at December 31, 2004 and $4.4 million at December 31, 2003.

Financial Investments

Financial investments recorded in "Other assets" consist of the following:

At December 31,	2004	2003

At December 31,	2004	2003
	(In millions)	
Financial limited partnerships	**$ 5.7**	$ 22.5
Leveraged leases		2.8
Total financial investments	**$ 5.7**	$ 25.3

Investments Classified as Available-for-Sale

We classify the following investments as available-for-sale:

- nuclear decommissioning trust funds, and
- trust assets securing certain executive benefits.

This means we do not expect to hold them to maturity, and we do not consider them trading securities.

We show the fair values, gross unrealized gains and losses, and amortized cost basis for all of our available-for-sale securities, in the following tables. We use specific identification to determine cost in computing realized gains and losses.

At December 31, 2004	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	**$ 786.1**	**$ 72.5**	**$ (2.5)**	**$ 856.1**
Corporate debt and U.S. treasuries	**73.7**	**0.7**	**(0.2)**	**74.2**
State municipal bonds	**94.3**	**2.9**	**(0.2)**	**97.0**
Totals	**$ 954.1**	**$ 76.1**	**$ (2.9)**	**$ 1,027.3**

At December 31, 2003	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$ 644.8	$ 30.7	$ (22.2)	$ 653.3
Corporate debt and U.S. treasuries	37.2	0.9		38.1
State municipal bonds	48.4	4.3		52.7
Totals	$ 730.4	$ 35.9	$ (22.2)	$ 744.1

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

In addition to the above securities, the nuclear decommissioning trust funds included $30.6 million at December 31, 2004 and $17.2 million at December 31, 2003 of cash and cash equivalents.

The preceding tables include $73.3 million in 2004 of net unrealized gains and $13.7 million in 2003 of net unrealized gains associated with the nuclear decommissioning trust funds that are reflected as a change in the nuclear decommissioning trust funds in our Consolidated Balance Sheets.

We have unrealized losses relating to certain available-for-sale investments included in our decommissioning trust funds. We believe these losses are temporary in nature and expect the investments to recover their value in the future given the long-term nature of these investments. Decommissioning will not occur until the operating licenses for our nuclear facilities expire. We show the fair values and unrealized losses of our investments that were in a loss position at December 31, 2004 and 2003.

At December 31, 2004

	Less than 12 months		12 months or more		Total	
Description of Securities	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
			(In millions)			
Marketable equity securities	**$ 23.6**	**$ (2.4)**	**$**	**$**	**$ 23.6**	**$ (2.4)**
Corporate debt and U.S. treasuries	**15.3**	**(0.1)**	**10.1**	**(0.1)**	**25.4**	**(0.2)**
State municipal bonds	**18.7**	**(0.2)**	**3.3**		**22.0**	**(0.2)**
Total temporarily impaired securities	**$ 57.6**	**$ (2.7)**	**$ 13.4**	**$ (0.1)**	**$ 71.0**	**$ (2.8)**

At December 31, 2003

	Less than 12 months		12 months or more		Total	
Description of Securities	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**	**Fair Value**	**Unrealized Losses**
			(In millions)			
Marketable equity securities	$ 210.7	$ (2.7)	$ 308.2	$ (19.2)	$ 518.9	$ (21.9)
Corporate debt and U.S. treasuries	16.9				16.9	
State municipal bonds			0.7		0.7	
Total temporarily impaired securities	$ 227.6	$ (2.7)	$ 308.9	$ (19.2)	$ 536.5	$ (21.9)

Gross and net realized gains and losses on available-for-sale securities, excluding the gains on our sales of the Orion investment, were as follows:

	2004	**2003**	**2002**

	2004	2003	2002
		(In millions)	
Gross realized gains	**$ 4.1**	$ 6.7	$ 6.0
Gross realized losses	**(7.7)**	(6.1)	(9.5)
Net realized (losses) gains	**$ (3.6)**	$ 0.6	$ (3.5)

Gross realized losses for 2004 include $4.5 million pre-tax impairment charge we recognized on a nuclear decommissioning trust fund investment that we believed represented an other than temporary decline in value.

The corporate debt securities, U.S. Government agency obligations, and state municipal bonds mature on the following schedule:

At December 31, 2004

	(In millions)
Less than 1 year	$ 15.6
1-5 years	42.2
5-10 years	69.3
More than 10 years	44.1
Total maturities of debt securities	$ 171.2

5 Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net assets acquired. Our goodwill balance is primarily related to our merchant energy business acquisitions that occurred in 2002 and 2003. We discuss our acquisitions in more detail in *Note 15*. The changes in the carrying amount of goodwill for the years ended December 31, 2004 and 2003 are as follows:

2004	Balance at January 1,	Goodwill Acquired	Other(a)	Balance at December 31,
		(In millions)		
Goodwill	**$ 146.3**	**$**	**$ (1.5)**	**$ 144.8**

2003	Balance at January 1,	Goodwill Acquired	Other(a)	Balance at December 31,
		(In millions)		
Goodwill	$ 118.2	$ 27.5	$ 0.6	$ 146.3

(a) Other represents purchase price adjustments

Goodwill is not amortized, rather it is evaluated for impairment at least annually. We evaluated our goodwill in 2004 and determined that it was not impaired. For tax purposes, $115.7 million of our goodwill balance is deductible.

Intangible Assets Subject to Amortization

Intangible assets with finite lives are subject to amortization over their estimated useful lives. The primary assets included in this category are as follows:

At December 31,	*2004*			*2003*		
	Gross Carrying Amount	Accumul-ated Amortiz-ation	Net Asset	Gross Carrying Amount	Accumul-ated Amortiz-ation	Net Asset
			(In millions)			
Software	**$ 388.4**	**$ 205.4**	**$ 183.0**	$ 285.6	$ 155.1	$ 130.5
Acquired energy contracts (net)	**185.2**	**84.8**	**100.4**	182.5	36.7	145.8
Permits and licenses	**37.7**	**5.7**	**32.0**	28.8	3.2	25.6
Operating manuals and procedures	**38.6**	**4.5**	**34.1**	12.5	2.7	9.8
Other	**20.0**	**12.1**	**7.9**	22.6	10.7	11.9
Total	**$ 669.9**	**$ 312.5**	**$ 357.4**	$ 532.0	$ 208.4	$ 323.6

BGE recorded intangible assets with a gross carrying amount of $253.1 million and accumulated amortization of $161.2 million in 2004 and a gross carrying amount of $212.2 million and accumulated amortization of $127.3 million in 2003 and are included in the table above. Substanitally all of BGE's intangible assets relate to software.

Acquired energy contracts (net) represent the fair value of a contract at the time of contract acquisition, which includes contracts acquired as part of a business, asset, or portfolio acquisition. Energy contracts acquired in connection with a business combination can either be an asset or a liability and are reflected on a net basis in the table above.

We recognized amortization expense related to our intangible assets as follows:

$114.2 million, of which BGE recognized $41.4 million, during 2004

$84.6 million, of which BGE recognized $33.0 million, during 2003, and

$46.4 million, of which BGE recognized $29.2 million, during 2002.

The following is our, and BGE's, estimated amortization expense for 2005 through 2009 for the intangible assets included in our, and BGE's, Consolidated Balance Sheets at December 31, 2004:

Year Ended December 31,	***2005***	***2006***	***2007***	***2008***	***2009***
			(In millions)		
Estimated amortization expense Nonregulated businesses	$ 53.6	$ 51.9	$ 36.1	$ 31.2	$ 27.8
Estimated amortization expense BGE	31.0	22.4	22.1	21.4	21.2
Total estimated amortization expense Constellation Energy	$ 84.6	$ 74.3	$ 58.2	$ 52.6	$ 49.0

6 Regulatory Assets (net)

As discussed in *Note 1*, the Maryland PSC and the FERC provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain regulated expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (using amortization) when we include them in the rates we charge our customers.

We summarize regulatory assets and liabilities in the following table, and we discuss each of them separately below.

At December 31,		**2004**		**2003**
		(In millions)		
Electric generation-related regulatory asset	**$**	**192.4**	$	211.3
Net cost of removal		**(132.5)**		(147.8)
Income taxes recoverable through future rates (net)		**74.9**		81.8
Deferred postretirement and postemployment benefit costs		**25.8**		29.0
Deferred environmental costs		**17.6**		20.4
Deferred fuel costs (net)		**5.9**		11.9
Workforce reduction costs		**14.1**		21.2
Other (net)		**(2.8)**		1.7
Total regulatory assets (net)	**$**	**195.4**	$	229.5

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE does not meet the requirements for the application of SFAS No. 71 for the electric generation portion of its business. In accordance with SFAS No. 101, *Regulated Enterprises Accounting for the Discontinuation of Application of FASB Statement No. 71*, and EITF 97-4, *Deregulation of the Pricing of Electricity Issues Related to the Application of FASB Statements No. 71 and 101*, all individual generation-related regulatory assets and liabilities must be eliminated from our balance sheet unless these regulatory assets and liabilities will be recovered in the regulated portion of the business. BGE wrote-off all of its individual, generation-related regulatory assets and liabilities. BGE established a single, new generation-related regulatory asset for amounts to be collected through its regulated transmission and distribution business. The new regulatory asset is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

A portion of this regulatory asset represents the decommissioning and decontamination fund payment for federal uranium enrichment facilities that do not earn a return on the rate base investment. These amounts were $10.5 million at December 31, 2004 and $13.4 million at December 31, 2003. Prior to the deregulation of electric generation, these costs were recovered through the electric fuel rate mechanism, and were excluded from rate base. We will continue to amortize this amount through 2008.

Net Cost of Removal

As discussed in *Note 1*, we use the composite depreciation method for the regulated business. This method is currently an acceptable method of accounting under accounting principles generally accepted in the United States of America 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 were provided for over the life of those assets as a component of depreciation expense. However, effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* In addition to providing the accounting requirements for recognizing an estimated liability for legal obligations associated with the retirement of tangible long-lived assets, SFAS No. 143 precludes the recognition of expected net future costs of removal as a component of depreciation expense or accumulated depreciation.

BGE is required by the Maryland PSC to use the composite depreciation method, including cost of removal, under regulatory accounting. In accordance with SFAS No. 71, BGE continues to accrue for the future cost of removal for its regulated gas and electric assets by increasing its regulatory liability. This liability is relieved when actual removal costs are incurred.

Income Taxes Recoverable Through Future Rates (net)

As described in *Note 1*, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* and SFAS No. 112, *Employers' Accounting for Postemployment Benefits,* in excess of the costs we included in the rates we charge our customers. We began amortizing these costs over a 15-year period in 1998.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in *Note 12*. We are amortizing $21.6 million of these costs (the amount we had incurred through October 1995) and $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders.

Deferred Fuel Costs

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of natural gas and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from or refund them to our customers.

In December 2002, a Hearing Examiner from the Maryland PSC issued a proposed order related to our annual gas adjustment clause review disallowing $7.7 million of a previously established regulatory asset of $9.4 million for certain credits that were over-refunded to customers through our market-based rates. BGE reserved the $7.7 million as disallowed fuel costs in the fourth quarter of 2002. In August 2003, the Maryland PSC issued an order authorizing us to recover the $7.7 million and we reinstated the $9.4 million regulatory asset.

We exclude gas deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through our gas cost adjustment clauses.

Workforce Reduction Costs

The portions of the costs associated with our VSERP and workforce reduction programs that relate to BGE's gas business are deferred as regulatory assets in accordance with the Maryland PSC's orders in prior rate cases. These costs are amortized over 5-year periods.

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7 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. BGE employees participate in the benefit plans that we offer. We describe each of our plans separately below. Nine Mile Point offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. The benefits for Nine Mile Point are included in the tables beginning on the next page.

We use a December 31 measurement date for our pension, postretirement, other postemployment, and employee savings plans.

Pension Benefits

We sponsor several defined benefit pension plans for our employees. These include basic qualified plans that most employees participate in and several nonqualified plans that are available only to certain employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

Sometimes we amend the plans retroactively. These retroactive plan amendments require us to recalculate benefits related to participants' past service. We amortize the change in the benefit costs from these plan amendments on a straight-line basis over the average remaining service period of active employees.

We fund the qualified plans by contributing at least the minimum amount required under Internal Revenue Service (IRS) regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2004 and 2003 were mostly marketable equity and fixed income securities.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover the vast majority of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels or final base pay. We do not fund these plans.

For nearly all of the health care plans, retirees make contributions to cover a portion of the plan costs.

Contributions for employees who retire after June 30, 1992 are calculated based on age and years of service. The amount of retiree contributions increases based on expected increases in medical costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs.

Effective in 2002, we amended our postretirement medical plans for all subsidiaries other than Nine Mile Point. Our contributions for retiree medical coverage for future retirees that were under the age of 55 on January 1, 2002 are capped at the 2002 level. We also amended our plans to increase the Medicare eligible retirees' share of medical costs.

In 2003, the President signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act). This legislation provides a prescription drug benefit for Medicare beneficiaries, a benefit that we provide to our Medicare eligible retirees. Our actuaries concluded that prescription drug benefits available under our postretirement medical plan are currently "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Act. This conclusion requires that we meet both the "gross test" and "net test" regulations. Our prescription drug plan provides a higher level of benefits than Medicare Part D, thereby satisfying the "gross test". Our share of these costs exceeds that of Medicare Part D, thereby satisfying the "net test" method.

The expected subsidy will offset or reduce our share of the cost of the underlying postretirement prescription drug coverage. The estimated impact of this legislation reduced our Accumulated Postretirement Benefit Obligation by $30.6 million at January 1, 2004 and our annual postretirement benefit expense in 2004 by $4.0 million. Final implementation guidance was issued in January 2005. This guidance will not have a material impact on our estimated impact of this legislation. This subsidy will reduce estimated 2006 cash per capita medical costs from $3,199 to $2,671, or 17%.

Additional Minimum Pension Liability Adjustment

Our pension accumulated benefit obligation has exceeded the fair value of our plan assets since 2001. At December 31, 2004 and 2003, our pension obligations were greater than the fair value of our plan assets for our qualified and our nonqualified pension plans as follows:

	Qualified Plans			
At December 31, 2004	**Nine Mile**	**Other**	**Non-Qualified Plans**	**Total**
		(In millions)		
Accumulated benefit obligation	**$ 122.1**	**$ 1,185.9**	**$ 46.1**	**$ 1,354.1**
Fair value of assets	**78.6**	**1,005.8**		**1,084.4**
Unfunded obligation	**$ 43.5**	**$ 180.1**	**$ 46.1**	**$ 269.7**

	Qualified Plans			
At December 31, 2003	**Nine Mile**	**Other**	**Non-Qualified Plans**	**Total**
		(In millions)		
Accumulated benefit obligation	$ 98.3	$ 1,044.9	$ 37.1	$ 1,180.3
Fair value of assets	66.7	887.9		954.6
Unfunded obligation	$ 31.6	$ 157.0	$ 37.1	$ 225.7

As required under SFAS No. 87, we recorded additional minimum pension liability adjustments as follows:

	Increase (Decrease)			
			Accumulated Other Comprehensive Income (Loss)	
	Pension Liability Adjustment	**Intangible Asset ***	**Pre-tax**	**After-tax**
		(In millions)		
2001	$ 133.0	$ 59.0	$ (74.0)	$ (44.7)

	Increase (Decrease)			
2002	189.5	(5.8)	(195.3)	(118.1)
2003	(27.3)	(6.5)	20.8	12.6
2004	64.4	(6.1)	(70.5)	(42.6)
Total	$ 359.6	$ 40.6	$ (319.0)	$ (192.8)

* *Included in "Other assets" in our Consolidated Balance Sheets.*

Obligations, Assets, and Funded Status

In June 2004, we assumed pension and postretirement benefit obligations for new employees in connection with the acquisition of the R.E. Ginna Nuclear Plant (Ginna). The sellers of Ginna transferred assets into our qualified plan trust. We discuss the Ginna acquisition further in *Note 15*. As a result of a workforce reduction initiative in the generation business, pension and postretirement special termination benefits were recorded in December 2004. We discuss the workforce reduction initiative further in *Note 2*. We show the change in the benefit obligations, plan assets, and funded status of the pension and postretirement benefit plans in the following tables.

	Pension Benefits		Postretirement Benefits	
	2004	**2003**	**2004**	**2003**
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	**$ 1,326.0**	$ 1,247.5	**$ 430.8**	$ 415.4
Service cost	**40.1**	33.7	**6.5**	6.1
Interest cost	**82.4**	81.3	**22.6**	26.3
Plan participants' contributions			**5.8**	6.1
Actuarial loss (gain)	**117.1**	76.0	**(17.2)**	11.4
Plan amendments		(0.4)		
Ginna acquisition	**40.5**		**6.1**	
Special termination benefits	**2.4**		**1.2**	
Benefits paid (1)	**(95.3)**	(112.1)	**(32.6)**	(34.5)
Benefit obligation at December 31	**$ 1,513.2**	$ 1,326.0	**$ 423.2**	$ 430.8

(1) Benefits paid include annuity payments, lump-sum distributions, and transfers to nonqualified deferred compensation plans.

	Pension Benefits 2004	Pension Benefits 2003	Postretirement Benefits 2004	Postretirement Benefits 2003
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$ 954.6**	$ 767.7	**$**	$
Actual return on plan assets	**114.1**	183.6		
Employer contribution	**60.2**	115.4	**26.7**	28.4
Plan participants' contributions			**5.9**	6.1
Ginna acquisition	**50.8**			
Benefits paid (1)	**(95.3)**	(112.1)	**(32.6)**	(34.5)
Fair value of plan assets at December 31	**$ 1,084.4**	$ 954.6	**$**	$

(1) Benefits paid include annuity payments, lump-sum distributions, and transfers to nonqualified deferred compensation plans.

At December 31,	Pension Benefits 2004	Pension Benefits 2003	Postretirement Benefits 2004	Postretirement Benefits 2003
	(In millions)			
Funded Status				
Funded Status	**$ (428.8)**	$ (371.4)	**$ (423.2)**	$ (430.8)
Unrecognized net actuarial loss	**480.8**	397.0	**121.1**	140.6
Unrecognized prior service cost	**37.9**	43.9	**(36.7)**	(40.2)
Unrecognized transition obligation			**17.0**	19.2
Pension liability adjustment	**(359.6)**	(295.2)		
Accrued benefit cost	**$ (269.7)**	$ (225.7)	**$ (321.8)**	$ (311.2)

Net Periodic Benefit Cost

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

Year Ended December 31,	2004	2003	2002
	(In millions)		
Components of net periodic pension benefit cost			
Service cost	**$ 40.1**	$ 33.7	$ 29.6
Interest cost	**82.3**	81.3	82.2
Expected return on plan assets	**(97.9)**	(95.0)	(91.0)
Amortization of unrecognized prior service cost	**5.8**	5.8	6.7
Recognized net actuarial loss	**14.3**	5.0	1.3
Amount capitalized as construction cost	**(4.5)**	(2.6)	(2.9)
Net periodic pension benefit cost (1)	**$ 40.1**	$ 28.2	$ 25.9

(1) Net periodic pension benefit cost excludes SFAS No. 88 settlement charge of $2.8 million and termination benefits of $2.4 million in 2004, SFAS No. 88 settlement charge of $2.8 million in 2003, and SFAS No. 88 settlement charge of $29.6 million and termination benefits of $43.0 million in

2002. BGE's portion of our net periodic pension benefit costs was $8.6 million in 2004, $4.3 million in 2003, and $5.0 million in 2002.

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

Year Ended December 31,	**2004**	2003	2002
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	**$ 6.5**	$ 6.1	