CONSTELLATION ENERGY GROUP INC
Form 10-K
February 27, 2008

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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, 2007**

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.
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 if Constellation Energy Group, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o.

Indicate by check mark if Baltimore Gas and Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o.

Indicate by check mark if Constellation Energy Group, Inc. is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý.

Indicate by check mark if Baltimore Gas and Electric Company is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý.

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 a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ý Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

Large accelerated filer o Accelerated filer o Non-accelerated filer ý Smaller reporting company o

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

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

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 30, 2007 was approximately $15,630,501,504 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE
177,923,807 SHARES OUTSTANDING ON JANUARY 31, 2008.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for the 2008 Annual Meeting of Shareholders for Constellation Energy Group, Inc.

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, freight, and emission allowances,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,
- the timing and extent of deregulation of, and competition in, the energy markets, and the rules and regulations adopted in those markets,
- uncertainties associated with estimating natural gas reserves, developing properties, and extracting natural gas,
- regulatory or legislative developments federally, in Maryland, or in other states that affect deregulation, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,
- the ability of our regulated and nonregulated businesses to comply with complex and/or changing market rules and regulations,
- the ability of Baltimore Gas and Electric Company (BGE) to recover all its costs associated with providing customers service,
- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, 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,
- the ability to successfully identify and complete acquisitions and sales of businesses and 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 an energy company that 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 energy and capacity requirements (load-serving) of, and providing other energy products and risk management services for, various 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. BGE was incorporated in Maryland in 1906.

Our other nonregulated businesses:

- design, construct, and operate renewable energy, heating, cooling, and cogeneration facilities, and provide various energy-related services, including energy consulting, 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.

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, Insider Trading Policy, Policy and Procedures with respect to Related Person Transactions, and Information Disclosure Policy, and the charters of the Audit, Compensation and Nominating and Corporate Governance Committees of the Board of Directors. Copies of each of these documents may be printed from our 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 that 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 other items, in *Note 3 to Consolidated Financial Statements*.

	Unaffiliated Revenues			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated

	Unaffiliated Revenues			
2007	83%	12%	4%	1%
2006	83	11	5	1
2005	81	12	6	1

	Net Income (1)			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2007	83%	12%	3%	2%
2006	77	16	5	2
2005	67	28	5	

	Total Assets			
	Merchant Energy	Regulated Electric	Regulated Gas	Other Nonregulated
2007	73%	20%	6%	1%
2006	75	17	6	2
2005	77	16	6	1

(1)
Excludes income from discontinued operations in 2007, 2006 and 2005 and cumulative effects of changes in accounting principles in 2005 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 products to wholesale and retail customers, allowing us to manage energy price risk over geographic regions and time.

Our merchant energy business includes:

- a power generation and development operation that owns, operates, and maintains fossil and renewable generating facilities, and holds interests in qualifying facilities, fuel processing facilities and power projects in the United States,
- a nuclear generation operation that owns, operates and maintains nuclear generating facilities and oversees our new nuclear development activities,
- a customer supply operation that primarily provides energy products and services relating to load-serving obligations to wholesale and retail customers, including distribution utilities, cooperatives, aggregators, and commercial, industrial and governmental customers, and
- a global commodities operation that manages contractually controlled physical assets, including generation facilities, natural gas properties, international coal and freight assets, provides risk management services, and trades energy and energy-related commodities.

Our merchant energy business:

- provided approximately 32,700 megawatts (MW) of peak load in the aggregate to distribution utilities, municipalities, and commercial, industrial, and governmental customers during 2007,
- provided approximately 410,000 million British Thermal Units (mmBTUs) of natural gas to commercial, industrial, and governmental customers during 2007,
- delivered approximately 28 million tons of coal to international and domestic third-party customers and to our own fleet during 2007, and
- managed approximately 8,730 MW of generation capacity as of December 31, 2007.

For years 2007 and prior, 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 Mid-Atlantic region of the PJM Interconnection (PJM). This also includes active portfolio management of 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. As discussed in *Note 2 to Consolidated Financial Statements*, the sale of the High Desert facility in 2006 resulted in a reclassification of its results to discontinued operations.
- Wholesale Competitive Supply our marketing, risk management, and trading operation that provides energy products and services primarily to distribution utilities, power generators, and other wholesale customers. We also include in our wholesale competitive supply results our global coal sourcing and logistics services and upstream and downstream natural gas services.
- Retail Competitive Supply our operation that provides electric and natural gas energy products and services to commercial, industrial, and governmental customers.
- Other our investments in qualifying facilities and domestic power projects and our generation operations and maintenance services.

Beginning in 2008, we will analyze our merchant energy business in terms of Generation, Customer Supply and Global Commodities activities.

- Generation will encompass all of our generating assets, including those currently included in the Mid-Atlantic Region, Plants with Power Purchase Agreements and Other.

- Customer Supply will encompass the current Retail Competitive Supply and the power load-serving portion of Wholesale Competitive Supply.

- Global Commodities will encompass the remaining Wholesale Competitive Supply businesses including our marketing, risk management, and trading operations, global coal sourcing and logistics services, and upstream and downstream natural gas services.

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

Mid-Atlantic Region

We own 6,355 MW of fossil, nuclear, and hydroelectric generation capacity in the Mid-Atlantic Region. The output of these plants is managed by our global commodities operation and is hedged through a combination of power sales to wholesale and retail market participants. 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.

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 facility that commenced operations in mid-2001. The assets transferred from BGE are subject to the lien of BGE's mortgage. We expect the assets to be released from this lien following payment in March 2008 of the last series of bonds outstanding under the mortgage and the subsequent discharge of the mortgage.

Our merchant energy business supplies BGE with a portion of its market-based standard offer service obligation. For 2007, the peak load supplied to BGE was approximately 3,200 MW.

Plants with Power Purchase Agreements

We own 2,134 MW of nuclear generation capacity with power purchase agreements for a significant portion of their output. Our facilities with power purchase agreements are the Nine Mile Point Nuclear Station (Nine Mile Point) and the R.E. Ginna Nuclear Plant (Ginna). Both Nine Mile Point and Ginna are located within the New York Independent System Operator (NYISO) region.

We own 100% of Nine Mile Point Unit 1 (620 MW) and 82% of Unit 2 (933 MW). The remaining interest in Nine Mile Point Unit 2 is owned by the Long Island Power Authority (LIPA). Unit 1 entered service in 1969 and is licensed to operate until 2029. Unit 2 entered service in 1988 and is licensed to operate until 2046.

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 our share of Nine Mile Point's output is managed by our global commodities 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 our ownership percentage of Unit 2, a predetermined strike 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 average strike price for the first year of the revenue sharing agreement is $40.75 per MWH. The strike price increases two percent annually beginning in the second year of the revenue sharing agreement. 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 LIPA. LIPA 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.

We own 100% of the Ginna nuclear facility. Ginna consists of a 581 MW reactor that entered service in 1970 and is licensed to operate until 2029. We sell up to 80% of the plant's output and capacity to the former owners for 10 years ending in 2014 at an average price of $44.00 per MWH under a long term unit contingent power purchase agreement. The remaining output is managed by our global commodities operation and sold into the wholesale market.

Competitive Supply

We are a leading supplier of energy products and services to wholesale customers and retail commercial, industrial, and governmental customers. In 2007, our wholesale competitive supply operation provided approximately 16,500 peak MWs of wholesale full requirements load-serving products. During 2007, our retail competitive supply activities served approximately 16,200 MW of peak load and approximately 410,000 mmBTUs of natural gas.

Wholesale and Retail Load-Serving Activities

Our wholesale competitive supply operation structures transactions that serve the full energy and capacity requirements of various customers 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.

Our retail competitive supply operation structures transactions to supply full energy and capacity requirements and provide natural gas, transportation, and other energy products and services to retail, commercial, industrial, and governmental customers. 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 and natural gas purchase agreements with third parties, unit contingent purchases from generation companies,

our generation assets,

regional power pools,

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, and exchange traded electricity and natural gas contracts.

Portfolio Management and Trading

We continue to identify and pursue opportunities which can generate additional returns through portfolio management and trading activities within our business. These opportunities have increased due to the significant growth in scale of our competitive supply operations. In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

Our global commodities operation actively uses energy and energy-related commodities and contracts for those commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. We use both derivative and nonderivative contracts in managing our portfolio of energy sales and purchase contracts. Generally, we expect to use both derivative and nonderivative contracts to hedge our portfolio in order to reduce volatility. Although a substantial portion of our portfolio is hedged, we are able to identify opportunities to deploy risk capital to increase the value of our accrual positions, which we characterize as portfolio management.

We trade energy and energy-related contracts and commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines, and could have a material impact on our financial results. We discuss the impact of our trading activities and value at risk in more detail in *Item 7. Management's Discussion and Analysis.*

These activities involve the use of physical commodity inventories and 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 merchant energy business to:

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

Coal and International Services

Our global commodities operation participates in global coal sourcing activities by providing coal and coal-related logistical services for the variable or fixed supply needs of global customers. In late 2006, we formed a shipping joint venture that will own and operate six freight ships for the delivery of coal and other dry bulk freight products. We own a 50% interest in this joint venture. In 2007, we delivered approximately 28 million tons of coal to global customers and to our own generation fleet. Additionally, we entered into power, natural gas, freight, and emissions transactions outside of the United States. We also include in our coal services the results from our synthetic fuel processing facility in South Carolina. In 2008, these synthetic fuel processing facilities will be decommissioned.

We will continue to evaluate new international opportunities, including expanding our coal sourcing, freight, power, natural gas and emissions activities outside of the United States.

Natural Gas Services

Our global commodities operation includes upstream (exploration and production) and downstream (transportation and storage) natural gas operations. Our upstream activities include the acquisition, development, and exploitation of natural gas properties. Our downstream activities include providing natural gas to various customers, including large utilities, commercial and industrial customers, power generators, wholesale marketers, and retail aggregators.

In 2007, 2006 and 2005, we acquired working interests in gas producing fields. We discuss these acquisitions in more detail in *Note 15 to Consolidated Financial Statements*.

In November 2006, we completed the initial public offering of Constellation Energy Partners LLC (CEP), a limited liability company that we formed. CEP is principally engaged in the acquisition, development, and exploitation of natural gas properties. During 2007, CEP conducted additional equity issuances in which we did not participate, and our ownership percentage fell below 50 percent. Therefore, in 2007, we deconsolidated CEP and began to account for our interest under the equity method of accounting. We discuss the impact of CEP's equity issuances and deconsolidation on our financial results in more detail in *Note 2 to Consolidated Financial Statements*.

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. Of those, the electric generation projects are considered qualifying facilities under the Public Utility Regulatory Policies Act of 1978. 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.

UniStar Nuclear

In 2005, we formed UniStar Nuclear, LLC (UniStar), a joint enterprise with AREVA NP, Inc., (AREVA) to introduce the advanced design Evolutionary Power Reactor to the U.S. market. Upon conversion to U.S. electrical standards, the technology will be known as the U.S. EPR.

In August 2007, we formed a joint venture, UniStar Nuclear Energy, LLC (UNE) with an affiliate of Electricite de France, SA (EDF). We have a 50% ownership interest in this joint venture to develop, own, and operate new nuclear projects in the United States and Canada. The agreement with EDF includes a phased-in cash investment of $625 million by EDF in UNE. Initially, EDF invested $350 million of cash in UNE, and we contributed UniStar and other UniStar-related assets, which had a book value of $49 million, and the right to develop new nuclear projects at our existing nuclear plant locations. Upon reaching certain licensing milestones, EDF will contribute up to an additional $275 million of cash in UNE for a total of $625 million. In the event that the joint venture is terminated, the remaining equity of UNE, after certain expenses, will be divided equally between Constellation Energy and EDF pursuant to the joint venture agreement.

In connection with this joint venture, we entered into an investor agreement with EDF under which EDF may purchase in the open market up to a total of 9.9% of our outstanding common stock during the next five years, with a limit of 5% ownership during the first twelve months of the agreement. EDF has agreed to vote any shares of our common stock owned by it in the manner recommended by our board of directors and not take any actions that seek control of Constellation Energy during the next five years.

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2007 and our generation based on actual output by fuel type in 2007 were as follows:

Fuel	Capacity Owned	Generation
Nuclear	45%	61%
Coal	31	35
Natural Gas	7	
Oil	8	
Renewable and Alternative (1)	5	4
Dual (2)	4	

(1) *Includes solar, geothermal, hydro, waste coal 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 of our nuclear facilities over the past five years (including periods prior to our acquisition of Ginna in June 2004) is presented in the following table:

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH*	Capacity Factor	MWH	Capacity Factor
	(MWH in millions)					
2007	14.3	94%	12.3	90%	4.9	98%
2006	13.8	90	12.8	93	4.1	93
2005	14.7	97	12.7	93	4.0	93
2004	14.5	96	12.1	89	4.3	100
2003	13.7	93	12.2	90	3.9	90

**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 and Conversion	We have commitments that provide for sufficient quantities of uranium (concentrates and uranium hexafluoride) for the next several years.
Enrichment	We have commitments that provide for our uranium enrichment requirements for the next several years.
Fuel Assembly Fabrication	We have commitments for the fabrication of fuel assemblies for reloads required for the next several years for Calvert Cliffs Nuclear Power Plant, Inc. (Calvert Cliffs), Nine Mile Point and for Ginna.

The nuclear fuel markets are competitive, and prices can be volatile; however, we do not anticipate any significant problems in meeting our future supply 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 our nuclear generating facilities. 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 may not meet that obligation until 2017 at the earliest. This delay has required that we undertake additional actions to provide on-site fuel storage at our nuclear generating facilities, including the installation of on-site dry fuel storage capacity 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 the former owner's rights and obligations related to recovery of damages for DOE's failure to meet its contractual obligations were assigned to us. However, we have an obligation to reimburse the former owner for up to $10 million of any recovered damages for such claims.

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 2011. In addition, we can expand our temporary storage capacity at Calvert Cliffs to meet future requirements until approximately 2025. Nine Mile Point and Ginna are developing independent spent fuel storage installations at each of those facilities, which we expect to be completed in 2011 and 2010, respectively. Nine Mile Point and Ginna have sufficient storage capacity within the plant until the expected completion of the on-site independent spent fuel storage installations.

Cost for Decommissioning Nuclear Facilities

We are obligated to decommission our nuclear plants after 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 funds accumulated to pay for decommissioning Calvert Cliffs. At December 31, 2007, the external Calvert Cliffs trust fund assets were $457.4 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. BGE is collecting this amount on behalf of Calvert Cliffs. Any costs to decommission Calvert Cliffs in excess of this $520 million, in 1993 dollars adjusted for inflation, 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 $520 million, in 1993 dollars adjusted for inflation, BGE's ratepayers are obligated to pay, Calvert Cliffs may keep the difference.

In 2006, BGE received approval from the Maryland PSC to continue previously approved annual customer collections for decommissioning of approximately $18.7 million through December 31, 2016. BGE will be required to submit a filing to determine the level of customer contributions after December 31, 2016. Senate Bill 1, which was enacted in June 2006, requires BGE to provide credits to residential electric customers equal to the amount collected for decommissioning annually for 10 years beginning January 1, 2007. Under the provisions of Senate Bill 1, we are required to apply the collection of the nuclear decommissioning trust funds over the ten year period beginning January 1, 2007 toward the fulfillment of the decommissioning obligations of BGE ratepayers. As discussed in *Item 7. Management's Discussion and Analysis Business Environment Regulation Maryland Senate Bills 1 and 400* section, we have notified the State of Maryland of our intent to file an action challenging the legality of this Senate Bill 1 requirement.

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, 2007, the Nine Mile Point trust fund assets were $610.2 million.

The seller of Ginna 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 amount will be sufficient to cover our responsibility for decommissioning Ginna to a greenfield status. At December 31, 2007, the Ginna trust fund assets were $263.2 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 of SO_2/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 less than 1.60 lbs of SO_2/mmBTU

Coal deliveries to these facilities are made by rail and barge. Over the past few years, we expanded our coal sources through a variety of methods, 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 various international sources. While we primarily use coal produced from mines located in central and northern Appalachia, we are capable of switching to imported coals to manage our coal supply. Synthetic fuel will no longer be burned as an alternate source since tax credits for synthetic fuel expired on December 31, 2007. 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.

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. These plants are restricted to coal with sulfur content less than 2.0%.

The Panther Creek and Colver generating facilities' primary fuel source is waste coal. These facilities meet their annual requirements through existing reserves of mined and processed waste coal and through supply agreements with various terms.

All of our coal requirements reflect historical generating levels. The actual fuel quantities required can vary substantially from historical generating 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 under 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 1.0 million to 1.5 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor and Philadelphia marine terminals for distribution to the various generating plant locations. Also, based on normal burn practices, we require approximately 8.0 million to 11.0 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

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, transportation, or storage. 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, financial investors, banks and investment banks), some of which have greater financial resources.

States are considering different types of regulatory initiatives concerning competition in the power and gas industry, which makes a competitive assessment difficult. 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. Many states continue to support or expand retail competition and industry restructuring. Other states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, certain previously restructured states are considering reregulation of their retail markets. While there is significant activity in this area, 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.

As the market for commercial, industrial, and governmental energy supply continues to grow, we have experienced increased competition on a regional basis in our retail competitive supply activities. The increase in retail competition and the impact of wholesale power prices compared to the rates charged by local utilities has, in certain circumstances, reduced the margins that we realize from our customers. However, we believe that our experience and expertise in assessing and managing risk and our strong focus on customer service will help us to remain competitive during volatile or otherwise adverse market circumstances.

Merchant Energy Operating Statistics

		2007		2006		2005		2004		2003
Revenues *(In millions)*										
Mid-Atlantic Region	**$**	**3,462.2**	$	2,813.5	$	2,283.9	$	1,925.6	$	1,696.2
Plants with Power Purchase Agreements		**657.3**		650.5		665.9		555.3		463.3
Competitive Supply Retail		**9,086.3**		8,014.7		6,942.3		4,280.0		2,567.7
Competitive Supply Wholesale		**5,469.4**		5,612.7		4,672.3		3,353.8		2,703.9
Other		**69.3**		74.8		58.0		73.6		45.1
Total Revenues	**$**	**18,744.5**	$	17,166.2	$	14,622.4	$	10,188.3	$	7,476.2
Generation *(In millions)* MWH*		**51.6**		59.1		60.2		55.3		51.6

**Includes output from gas-fired plants until sale in December 2006.*

Operating statistics do not reflect the elimination of intercompany transactions.

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.

Electric Business

Electric 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, all customers can choose their electric energy supplier. 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, and regular maintenance.

Standard Offer Service

BGE is obligated to provide market-based standard offer service (SOS) to all of its electric customers. The SOS rates charged 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. As discussed in *Item 7. Management's Discussion and Analysis Regulated Electric Business Senate Bill 1 Credits* section, BGE is now required to credit to residential electric customers the shareholder return component of the administrative charge for residential SOS service.

Bidding to supply BGE's market-based standard offer service will occur from time to time through a competitive bidding process approved by the Maryland PSC. Successful bidders, which may include subsidiaries of Constellation Energy, will execute contracts with BGE for varying terms.

Commercial and Industrial Customers

BGE is obligated to provide market-based standard offer service to commercial and industrial customers for varying periods beyond June 30, 2004, depending on customer load.

In August 2006, the Maryland PSC issued an order indefinitely extending the obligation of Maryland utilities to provide SOS service for those commercial and industrial customers for which market-based standard offer service was scheduled to expire at the end of May 2007. The extended service will be provided on substantially the same terms as under the then existing service, except that wholesale bidding for service to some customers will be conducted more frequently.

BGE's obligation to provide market-based standard offer service to its largest commercial and industrial customers expired on May 31, 2005. BGE continues to provide an hourly-priced market-based standard offer service to those customers.

Residential Customers

As a result of the November 1999 Maryland PSC order regarding the deregulation of electric generation in Maryland, BGE's residential electric base rates were frozen until July 2006. Subsequent orders of the Maryland PSC specified that BGE would procure the power to serve residential customers beginning July 2006 via auctions to be conducted in late 2005 and early 2006. The procured power costs of these auctions would have resulted in an average electric residential customer bill increase of 72%. In June 2006, Senate Bill 1 was enacted, which, among other things:

- capped rate increases by BGE for residential SOS service at 15% from July 1, 2006 to May 31, 2007,
- gave residential SOS customers the option from June 1, 2007 until December 31, 2007 of paying a full market rate or choosing a short term rate stabilization plan in order to provide a smooth transition to market rates without adversely affecting the creditworthiness of BGE, and
- provided for full market rates for all residential SOS service starting January 1, 2008.

We further discuss the impacts of Senate Bill 1 and other recent legislation in *Item 7. Management's Discussion and Analysis Business Environment Regulation Maryland Senate Bills 1 and 400* section. 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. These programs include:

- two options for commercial and industrial customers to 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 and had the effect of reducing BGE's system peak load by 248 MW during the summer period in 2007.

BGE is also developing other programs designed to help BGE manage peak demand, improve system reliability and improve service to customers by giving customers greater control over their energy use.

Recently, the Maryland PSC approved full implementation of a demand response program, which will enable BGE to regulate participating customer energy use through the use of programmable thermostats and air conditioner load control devices at customer premises during peak demand periods. The Maryland PSC also approved the implementation of an advanced metering pilot program, which will enable BGE to improve customer service and offer special pricing as an incentive to customers to reduce energy use during peak demand periods and to detect power outages electronically. BGE has also initiated a program that will provide incentives to customers to use energy efficient products and to take other actions to conserve energy. We also discuss the demand response initiatives in *Item 7. Management's Discussion and Analysis Regulation Maryland Maryland PSC* section.

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains approximately 24,000 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of PJM. 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

	2007	2006	2005	2004	2003
Revenues *(In millions)*					
Residential	**$ 1,514.9**	$ 1,092.1	$ 1,066.6	$ 1,015.8	$ 959.0
Commercial					
Excluding Delivery Service Only	**577.4**	733.4	722.1	708.9	694.2
Delivery Service Only	**217.0**	149.4	107.5	78.6	66.1
Industrial					
Excluding Delivery Service Only	**31.6**	46.8	52.8	92.3	137.0
Delivery Service Only	**27.8**	26.2	28.0	21.3	18.2
System Sales and Deliveries	**2,368.7**	2,047.9	1,977.0	1,916.9	1,874.5
Other (A)	**87.0**	68.0	59.5	50.8	47.1
Total	**$ 2,455.7**	$ 2,115.9	$ 2,036.5	$ 1,967.7	$ 1,921.6
Distribution Volumes *(In thousands)* MWH					
Residential	**13,365**	12,886	13,762	13,313	12,754
Commercial					
Excluding Delivery Service Only	**4,364**	6,325	7,847	9,286	9,937
Delivery Service Only	**11,921**	9,392	7,967	5,767	4,982
Industrial					
Excluding Delivery Service Only	**287**	467	614	1,429	2,556
Delivery Service Only	**3,175**	2,988	3,122	2,562	1,780
Total	**33,112**	32,058	33,312	32,357	32,009
Customers *(In thousands)*					
Residential	**1,103.1**	1,093.3	1,084.1	1,072.1	1,061.7
Commercial	**116.7**	115.5	114.7	113.6	112.1
Industrial	**5.5**	5.2	5.0	4.8	4.9
Total	**1,225.3**	1,214.0	1,203.8	1,190.5	1,178.7

(A)
Primarily includes network integration transmission service 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 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.

In December 2005, the Maryland PSC issued an order granting BGE a $35.6 million annual increase in its gas base rates, which are the rates the Maryland PSC allows BGE to charge its customers for the cost of providing them delivery service plus a profit. In December 2006, the Baltimore City Circuit Court upheld the rate order. However, certain parties have filed an appeal with the Court of Special Appeals. We cannot provide assurance that the Maryland PSC's order will not be reversed in whole or in part or that certain issues will not be remanded to the Maryland PSC for reconsideration.

For customers that buy their gas from BGE, there is a market-based rates incentive mechanism. Under this market-based rates incentive mechanism, 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 flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism.

BGE purchases the natural gas it resells to customers directly from many producers and marketers. BGE has transportation and storage agreements that expire from 2008 to 2027.

BGE's current pipeline firm transportation entitlements to serve BGE's firm loads are 338,053 dekatherms (DTH) per day.

BGE's current maximum storage entitlements are 248,153 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 and 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. 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

	2007	2006	2005	2004	2003
Revenues *(In millions)*					
Residential					
Excluding Delivery Service Only	**$ 552.0**	$ 490.2	$ 558.5	$ 478.0	$ 444.5
Delivery Service Only	**19.0**	20.6	23.2	14.2	13.6
Commercial					
Excluding Delivery Service Only	**154.1**	148.9	174.4	135.4	128.6
Delivery Service Only	**41.2**	35.9	31.9	28.0	24.6
Industrial					
Excluding Delivery Service Only	**7.8**	7.5	10.5	9.4	11.5
Delivery Service Only	**22.1**	19.3	12.4	7.8	11.4
System Sales and Deliveries	**796.2**	722.4	810.9	672.8	634.2
Off-System Sales	**157.4**	168.6	154.7	77.2	84.8
Other	**9.2**	8.5	7.2	7.0	7.0
Total	**$ 962.8**	$ 899.5	$ 972.8	$ 757.0	$ 726.0
Distribution Volumes *(In thousands)* DTH					
Residential					
Excluding Delivery Service Only	**39,199**	33,019	39,107	39,080	40,894
Delivery Service Only	**4,310**	3,948	5,423	6,053	6,640
Commercial					
Excluding Delivery Service Only	**12,464**	11,683	14,133	13,248	13,895
Delivery Service Only	**30,367**	25,695	28,993	34,120	29,138
Industrial					
Excluding Delivery Service Only	**658**	604	921	865	1,143
Delivery Service Only	**17,897**	20,325	19,357	14,310	18,399
System Sales and Deliveries	**104,895**	95,274	107,934	107,676	110,109
Off-System Sales	**19,963**	19,738	17,209	9,914	12,859
Total	**124,858**	115,012	125,143	117,590	122,968
Customers *(In thousands)*					
Residential	**602.3**	597.1	590.9	582.0	575.2
Commercial	**42.7**	42.3	42.0	41.6	41.1
Industrial	**1.2**	1.2	1.2	1.2	1.2
Total	**646.2**	640.6	634.1	624.8	617.5

Operating statistics do not reflect the elimination of intercompany transactions.

"Delivery service only" refers to BGE's delivery of commodity 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 it to engage in its 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, industrial and governmental customers. These energy products and services include:

- designing, constructing, and operating renewable energy, heating, cooling, and cogeneration facilities,
- energy savings projects and performance contracting,
- energy consulting and procurement 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.

Consolidated Capital Requirements

Our total capital requirements for 2007 were $1,665 million. Of this amount, $1,263 million was used in our nonregulated businesses and $402 million was used in our regulated business. We estimate our total capital requirements will be $2.5 billion in 2008.

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 ongoing compliance. Our capital expenditures were approximately $190 million during the five-year period 2003-2007 to comply with existing environmental standards and regulations. Our estimated environmental capital requirements for the next three years are approximately $575 million in 2008, $390 million in 2009, and $30 million in 2010.

Air Quality

Federal

The Clean Air Act created the basic framework for the federal and state regulation of air pollution.

National Ambient Air Quality Standards (NAAQS)
The NAAQS are federal air quality standards authorized under the Clean Air Act 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).

In order for states to achieve compliance with the NAAQS, the Environmental Protection Agency (EPA) adopted the Clean Air Interstate Rule (CAIR) in March 2005 to further reduce ozone and fine particulate pollution by addressing the interstate transport of SO_2 and nitrogen oxide (NO_x) emissions from fossil fuel-fired generating facilities located primarily in the Eastern United States.

In December 2006, the United States Court of Appeals for the District of Columbia Circuit ruled that a requirement to impose fees on emissions sources based on the previous ozone standard (Section 185 fees), which had been rescinded by the EPA in May 2005, remained applicable retroactive to November 2005 and remanded the issue to the EPA for reconsideration. A petition to the United States Supreme Court to hear an appeal was denied in January 2008. The EPA has announced that it intends to propose regulations by the summer of 2008 to address how Section 185 fees will be handled. In addition, the exact method of computing these fees has not been established and will depend in part on state implementation regulations that have not been proposed. Consequently, we are unable to estimate the ultimate financial impact of this matter in light of the uncertainty surrounding the anticipated EPA and state rulemakings. However, the final resolution of this matter, and any fees that are ultimately assessed could have a material impact on our financial results.

In September 2006, the EPA adopted a stricter NAAQS for particulate matter. We are unable to determine the impact that complying with the stricter NAAQS for particulate matter will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standard.

Hazardous Air Emissions

In March 2005, the EPA finalized the Clean Air Mercury Rule (CAMR) to reduce the emissions of mercury from coal-fired facilities through a market-based cap and trade program. CAMR was to affect all coal or waste coal fired boilers at our generating facilities. However, in February 2008, the United States Court of Appeals for the District of Columbia Circuit struck down CAMR. At this time, we cannot predict what actions the EPA will take in response to the court's decision. However, any action that requires the installation of additional emissions control technology beyond what is required under Maryland's Healthy Air Act and Clean Power Rule, which are discussed below, may require us to incur additional costs, which could have a material effect on our financial results.

New Source Review

In connection with its enforcement of the Clean Air Act's new source review requirements, in 2000, 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 responded to the EPA in 2001, 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.

State

Maryland has adopted the Healthy Air Act (HAA) and the Clean Power Rule (CPR), which establish annual SO_2, NO_x, and mercury emission caps for specific coal-fired units in Maryland, including units located at three of our facilities. The requirements of the HAA and the CPR for SO_2, NO_x, and mercury emissions are more stringent and apply sooner than those under CAIR. In addition, Pennsylvania has adopted regulations requiring coal-fired generating facilities located in Pennsylvania to reduce mercury emissions.

Several other states in the northeastern U.S. continue to consider more stringent and earlier SO_2, NO_x, and mercury emissions reductions than those required under CAIR or what would have been required under CAMR.

Capital Expenditure Estimates

We expect to incur additional environmental capital spending as a result of complying with the air quality laws and regulations discussed above. To comply with CAIR, HAA, and CPR, 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 air quality projects, which we expect will be approximately $550 million in 2008, $350 million in 2009, $15 million in 2010 and $25 million from 2011-2012.

Our estimates are subject to significant uncertainties including the timing of any additional federal and/or state regulations or legislation, such as any regulations adopted by the EPA in response to the court decision striking down CAMR, the implementation timetables for such regulation or legislation, and the specific amount of emissions reductions that will be required at our facilities. 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.

We believe that the additional air emission control equipment we plan to install will meet the emission reduction requirements under CAIR, HAA, and CPR. If additional emission reductions still are required, we will assess our various compliance alternatives and their related costs, and although we cannot yet estimate the additional costs we may incur, such costs could be material.

Global Climate Change

Although uncertainty remains as to the nature and timing of greenhouse gas emissions regulation, there is an increasing likelihood that such regulation will occur at the federal and/or state level. In the event that greenhouse gas emissions reduction legislation or regulations are enacted, we will assess our various compliance alternatives, which may include installation of additional environmental controls, modification of operating schedules or the closure of one or more of our coal-fired generating facilities. Any compliance costs we incur could have a material impact on our financial results.

However, to the extent greenhouse gas emissions are regulated through a federal, mandatory cap and trade greenhouse gas emissions program, we believe our business could also benefit. Our generation fleet currently has a carbon dioxide (CO_2) emission rate lower than the industry average with more than 60% of the fleet's output coming from low carbon dioxide emitting nuclear and hydroelectric plants. Our global commodities business has experience trading in the markets for emissions allowances and renewable energy credits.

In accordance with HAA requirements, Maryland became a full participant in the Northeast Regional Greenhouse Gas Initiative (RGGI) in April 2007. In October 2007, under RGGI, the Maryland Department of the Environment proposed auctioning 90% of CO_2 allowances associated with Maryland's power plants, which include plants owned by us. If this proposal is enacted, we could incur material costs to purchase CO_2 allowances necessary to offset emissions from our plants.

In addition, California has adopted regulations requiring our generating facilities in California to submit greenhouse gas emissions data to the state, which the state intends to use to develop a plan to reduce greenhouse gas emissions.

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

Water Quality

The Clean Water Act established the basic framework for federal and state regulation of water pollution control and requires facilities that discharge waste or storm water into the waters of the United States to obtain permits.

Water Intake Regulations

The Clean Water Act requires cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts. In July 2004, the EPA published final rules under the Clean Water Act for existing facilities that establish performance standards for meeting the best technology available for minimizing adverse environmental impacts. We currently have six facilities affected by the regulation. In January 2007, the United States Court of Appeals for the Second Circuit ruled that the EPA's rule did not properly implement the Clean Water Act requirements in a number of areas and remanded the rule to the EPA for reconsideration.

In response to this ruling, in July 2007, the EPA suspended the second phase of the regulations pending further rulemaking and directed the permitting authorities to establish controls for cooling water intake structures that reflect the best technology available for minimizing adverse environmental impacts. In November 2007, a number of parties petitioned the United States Supreme Court to hear an appeal of the Second Circuit's decision.

A decision by the United States Supreme Court on whether to hear the case is not expected until mid to late 2008. In addition, the EPA is expected to propose new regulations by the end of 2008. During this period, we will continue to evaluate our compliance options in light of the Second Circuit decision and the EPA's July 2007 order. At this time, we cannot estimate our compliance costs, but they could be material.

Hazardous and Solid Waste

We discuss proceedings relating to compliance with the Comprehensive Environmental Response, Compensation and Liability Act in *Note 12 to Consolidated Financial Statements*.

Our coal-fired generating facilities produce approximately two and a half million tons of combustion by-products ("ash") each year. The EPA announced in 2007 its intention to develop national standards to regulate this material as a non-hazardous waste, and has been developing or considering regulations governing the placement of ash in landfills, surface impoundments, sand/gravel surface mines and coal mines. In addition, the Maryland Department of the Environment proposed revised regulations governing the disposal, storage, use and placement of ash in December 2007. Final rules are expected in June 2008. Federal and state regulation has the potential to result in additional requirements. Depending on the scope of any final requirements, our compliance costs could be material.

As a result of these regulatory proposals and our current ash generation projections, we are exploring our options for the management 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 approximately $75 million. 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 10,200 employees at December 31, 2007. At the Nine Mile Point facility, approximately 510 employees are represented by the International Brotherhood of Electrical Workers, Local 97. The labor contract with this union expires in June 2011. 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 1A. Risk Factors

You should consider carefully the following risks, along with the other information contained in this Form 10-K. The risks and uncertainties described below are not the only ones that may affect us. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 7. Management's Discussion and Analysis. If any of the following events actually occur, our business and financial results could be materially adversely affected.

Our merchant energy business may incur substantial costs and liabilities and be exposed to price volatility and counterparty performance risk as a result of its participation in the wholesale energy markets.

We purchase and sell power and fuel in markets exposed to significant risks, including price volatility for electricity and fuel and the credit risks of counterparties with which we enter into contracts.

We use various hedging strategies in an effort to mitigate many of these risks. However, hedging transactions do not guard against all risks and are not always effective, as they are based upon predictions about future market conditions. The inability or failure to effectively hedge assets or fuel or power positions against changes in commodity prices, interest rates, counterparty credit risk or other risk measures could significantly impair future financial results.

Exposure to electricity price volatility. We buy and sell electricity in both the wholesale bilateral markets and spot markets, which expose us to the risks of rising and falling prices in those markets, and our cash flows may vary accordingly. At any given time, the wholesale spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. This is highly dependent on the regional generation market. In many cases, the next unit of electricity supplied would be supplied from generating stations fueled by fossil fuels, primarily coal, natural gas and oil. Consequently, the open market wholesale price of electricity may reflect the cost of coal, natural gas or oil plus the cost to convert the fuel to electricity and an appropriate return on capital. Therefore, changes in the supply and cost of coal, natural gas and oil may impact the open market wholesale price of electricity.

A portion of our power generation facilities operates wholly or partially without long-term power purchase agreements. As a result, power from these facilities is sold on the spot market or on a short-term contractual basis, which if not fully hedged may affect the volatility of our financial results.

Exposure to fuel cost volatility. Currently, our power generation facilities purchase a portion of their fuel through short-term contracts or on the spot market. Fuel prices can be volatile, and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs. As a result, fuel price increases may adversely affect our financial results.

Exposure to counterparty performance. Our merchant energy business enters into transactions with numerous third parties (commonly referred to as "counterparties"). In these arrangements, we are exposed to the credit risks of our counterparties and the risk that one or more counterparties may fail to perform under their obligations to make payments or deliver fuel or power. In addition, we enter into various wholesale transactions through Independent System Operators (ISOs). These ISOs are exposed to counterparty credit risks. Any losses relating to counterparty defaults impacting the ISOs are allocated to and borne by all other market participants in the ISO. These risks are enhanced during periods of commodity price fluctuations. Defaults by suppliers and other counterparties may adversely affect our financial results.

The operation of power generation facilities, including nuclear facilities, involves significant risks that could adversely affect our financial results.

We own and operate a number of power generation facilities. The operation of power generation facilities involves many risks, including start up risks, breakdown or failure of equipment, transmission lines, substations or pipelines, use of new technology, the dependence on a specific fuel source, including the transportation of fuel, or the impact of unusual or adverse weather conditions (including natural disasters such as hurricanes) or environmental compliance, as well as the risk of performance below expected or contracted levels of output or efficiency. This could result in lost revenues and/or increased expenses. Insurance, warranties, or performance guarantees may not cover any or all of the lost revenues or increased expenses, including the cost of replacement power. A portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures to keep it operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvement. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of the agreement or incurring a liability for liquidated damages.

We are subject to numerous environmental laws and regulations that require capital expenditures, increase our cost of operations and may expose us to environmental liabilities.

We are subject to extensive federal, state, and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife protection, the management of natural resources, and the protection of human health and safety that could, among other things, require additional pollution control equipment, limit the use of certain fuels, restrict the output of certain facilities, or otherwise increase costs. Significant capital expenditures, operating and other costs are associated with compliance with environmental requirements, and these expenditures and costs could become even more significant in the future as a result of regulatory changes.

For example, there is increasing likelihood that regulation of greenhouse gas emissions will occur at the federal and/or state level, which could increase our compliance and operating costs.

We are subject to liability under environmental laws for the costs of remediating environmental contamination. Remediation activities include the cleanup of current facilities and former properties, including manufactured gas plant operations and offsite waste disposal facilities. The remediation costs could be significantly higher than the liabilities recorded by us. Also, our subsidiaries are currently involved in proceedings relating to sites where hazardous substances have been released and may be subject to additional proceedings in the future.

We are subject to legal proceedings by individuals alleging injury from exposure to hazardous substances and could incur liabilities that may be material to our financial results. Additional proceedings could be filed against us in the future.

We may also be required to assume environmental liabilities in connection with future acquisitions. As a result, we may be liable for significant environmental remediation costs and other liabilities arising from the operation of acquired facilities, which may adversely affect our financial results.

Our generation business may incur substantial costs and liabilities due to its ownership and operation of nuclear generating facilities.

We own and operate nuclear power plants. Ownership and operation of these plants exposes us to risks in addition to those that result from owning and operating non-nuclear power generation facilities. These risks include normal operating risks for a nuclear facility and the risks of a nuclear accident.

Nuclear Operating Risks. The ownership and operation of nuclear generating facilities involve routine operating risks, including:

- mechanical or structural problems;
- inadequacy or lapses in maintenance protocols;
- impairment of reactor operation and safety systems due to human or mechanical error;
- costs of storage, handling and disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel;
- regulatory actions, including shut down of units because of public safety concerns, whether at our plants or other nuclear operators;
- limitations on the amounts and types of insurance coverage commercially available;
- uncertainties regarding both technological and financial aspects of decommissioning nuclear generating facilities; and
- environmental risks, including risks associated with changes in environmental legal requirements.

Nuclear Accident Risks. In the event of a nuclear accident, the cost of property damage and other expenses incurred may exceed our insurance coverage available from both private sources and an industry retrospective payment plan. In addition, in the event of an accident at one of our or another participating insured party's nuclear plants, we could be assessed retrospective insurance premiums (because all nuclear plant operators contribute to a nationwide catastrophic insurance fund). Uninsured losses or the payment of retrospective insurance premiums could each have a material adverse effect on our financial results.

Our generation growth plans may not achieve the desired financial results.

We may expand our generation capacity over the next several years through increasing the generating power of existing plants, the renovation of retired plants owned by us, and the construction or acquisition of new plants. The renovation, development, construction, and acquisition of additional generation capacity involves numerous risks. Any planned power uprates, construction, or renovation could result in cost overruns, lower than expected plant efficiency, and higher operating and other costs. With respect to the renovation of retired plants or the construction of new plants, we may incur significant sums for preliminary engineering, permitting, legal, and other expenses before it can be established whether a project is feasible, economically attractive, or capable of being financed.

If we were unable to complete the construction or renovation of a plant, we may not be able to recover our investment in the project. Furthermore, we may be unable to run any new, acquired or renovated plants as efficiently as projected, which could result in higher-than-projected operating and other costs that adversely affect our financial results.

We often rely on single suppliers and at times on single customers, exposing us to significant financial risks if either should fail to perform their obligations.

We often rely on a single supplier for the provision of fuel, water, and other services required for operation of a facility, and at times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that provide the support for any project debt used to finance the facility. The failure of any one customer or supplier to fulfill its contractual obligations could negatively impact our financial results. Consequently, our financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements.

Reduced liquidity in the markets in which we operate could impair our ability to appropriately manage the risks of our operations.

We are an active participant in energy markets through our competitive energy businesses. The liquidity of regional energy markets is an important factor in our ability to manage risks in these operations. Over the past several years, several merchant energy businesses have ended or significantly reduced their activities as a result of several factors including government investigations, changes in market design and deteriorating credit quality. As a result, several regional energy markets experienced a significant decline in liquidity. Liquidity in the energy markets can be adversely affected by various factors, including price volatility and the availability of credit. As a result, future reductions in liquidity may restrict our ability to manage our risks and this could impact our financial results.

We may not fully hedge our generation assets, competitive supply or other market positions against changes in commodity prices, and our hedging procedures may not work as planned.

To lower our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge a portion of our purchase and sale commitments, weather positions, fuel requirements, inventories of natural gas, coal and other commodities, and competitive supply. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. However, we may not cover the entire exposure of our assets or positions to market price volatility and the coverage will vary over time. Fluctuating commodity prices may negatively impact our financial results to the extent we have unhedged positions.

In addition, risk management tools and metrics such as daily value at risk, stop loss limits and liquidity guidelines are based on historical price movements. If price movements significantly or persistently deviate from historical behavior, the limits may not protect us from significant losses.

Our risk management policies and procedures may not always work as planned. As a result of these and other factors, we cannot predict with precision the impact that risk management decisions may have on our financial results.

The use of derivative contracts by us in the normal course of business could result in financial losses that negatively impact our financial results.

We use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks and to engage in trading activities. We could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform.

In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

A failure in our operational systems or infrastructure, or those of third parties, may adversely affect our financial results.

Our businesses are dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, accounting or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

We may also be subject to disruptions of our operational systems arising from events that are wholly or partially beyond our control (for example, natural disasters, acts of terrorism, epidemics, computer viruses and telecommunications outages). Third party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt one or more of our businesses, result in potential liability or reputational damage or otherwise have an adverse affect on our financial results.

We operate in deregulated segments of the electric and gas industries created by federal and state restructuring initiatives. If competitive restructuring of the electric or gas industries is reversed, discontinued, restricted or delayed, our business prospects and financial results could be materially adversely affected.

The regulatory environment applicable to the electric and natural gas industries has undergone substantial changes as a result of restructuring initiatives at both the state and federal levels. These initiatives have had a significant impact on the nature of the electric and natural gas industries and the manner in which their participants conduct their businesses. We have targeted the competitive segments of the electric and natural gas industries created by these initiatives.

Due to recent events in the energy markets, energy companies have been under increased scrutiny by state legislatures, regulatory bodies, capital markets and credit rating agencies. This increased scrutiny could lead to substantial changes in laws and regulations affecting us, including modifications to the auction processes in competitive markets and new accounting standards that could change the way we are required to record revenues, expenses, assets and liabilities. Recent proposals by the Maryland PSC relating to the structure of the electric industry in Maryland and various options for re-regulation of the industry is one example of how these laws and regulations can change. We cannot predict the future development of regulation in these markets or the ultimate effect that this changing regulatory environment will have on our business.

If competitive restructuring of the electric and natural gas markets is reversed, discontinued, restricted or delayed, or if the recent Maryland PSC proposals are implemented in a manner adverse to us, our business prospects and financial results could be negatively impacted.

Our financial results may be harmed if transportation and transmission availability is limited or unreliable.

We have business operations throughout the United States and internationally. As a result, we depend on transportation and transmission facilities owned and operated by utilities and other energy companies to deliver the electricity, coal, and natural gas we sell to the wholesale and retail markets, as well as the natural gas and coal we purchase to supply some of our generating facilities. If transportation or transmission is disrupted or capacity is inadequate, our ability to sell and deliver products may be hindered. Such disruptions could also hinder our ability to provide electricity, coal or natural gas to our customers or power plants and may materially adversely affect our financial results.

Our merchant energy business has contractual obligations to certain customers to provide full requirements service, which makes it difficult to predict and plan for load requirements and may result in increased operating costs to our business.

Our merchant energy business has contractual obligations to certain customers to supply full requirements service to such customers to satisfy all or a portion of their energy requirements. The uncertainty regarding the amount of load that our merchant energy business must be prepared to supply to customers may increase our operating costs. A significant under- or over-estimation of load requirements could result in our merchant energy business not having enough or having too much power to cover its load obligation, in which case it would be required to buy or sell power from or to third parties at prevailing market prices. Those prices may not be favorable and thus could increase our operating costs.

Our financial results may fluctuate on a seasonal and quarterly basis or as a result of severe weather.

Our business is affected by weather conditions. Our overall operating results may fluctuate substantially on a seasonal basis, and the pattern of this fluctuation may change depending on the nature and location of any facility we acquire and the terms of any contract to which we become a party. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities.

Generally, demand for electricity peaks in winter and summer and demand for gas peaks in the winter. Typically, when winters are warmer than expected and summers are cooler than expected, demand for energy is lower, resulting in less electric and gas consumption than forecasted. Depending on prevailing market prices for electricity and gas, these and other unexpected conditions may reduce our revenues and results of operations. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Severe weather can be destructive, causing outages and/or property damage. This could require us to incur additional costs. Catastrophic weather, such as hurricanes, could impact our or our customers' operating facilities, communication systems and technology. Unfavorable weather conditions may have a material adverse effect on our financial results.

A downgrade in our credit ratings could negatively affect our ability to access capital and/or operate our wholesale and retail competitive supply businesses.

We rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. If any of our credit ratings were to be downgraded, especially below investment grade, our ability to raise capital on favorable terms, including the commercial paper markets, could be hindered, and our borrowing costs would increase. Additionally, the business prospects of our wholesale and retail competitive supply businesses, which in many cases rely on the creditworthiness of Constellation Energy, would be negatively impacted. Some of the factors that affect credit ratings are cash flows, liquidity, the amount of debt as a component of total capitalization, and political, legislative and regulatory events.

In addition, the ability of BGE to recover its costs of providing service and timing of BGE's recovery could have a material adverse effect on the credit ratings of BGE and us.

We, and BGE in particular, are subject to extensive local, state and federal regulation that could affect our operations and costs.

We are subject to regulation by federal and state governmental entities, including the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, the Maryland PSC and the utility commissions of other states in which we have operations. In addition, changing governmental policies and regulatory actions can have a significant impact on us. Regulations can affect, for example, allowed rates of return, requirements for plant operations, recovery of costs, limitations on dividend payments and the regulation or re-regulation of wholesale and retail competition (including but not limited to retail choice and transmission costs).

BGE's distribution rates are subject to regulation by the Maryland PSC, and such rates are effective until new rates are approved. In addition, limited categories of costs are recovered through adjustment charges that are periodically reset to reflect current and projected costs. Inability to recover material costs not included in rates or adjustment clauses, including increases in uncollectible customer accounts that may result from higher gas or electric costs, could have an adverse effect on our, or BGE's, cash flow and financial position.

Energy legislation enacted in Maryland in June 2006 and April 2007 mandated that the Maryland PSC review Maryland's deregulated electricity market. In December 2007 and January 2008, the Maryland PSC issued interim reports that addressed the costs and benefits of options for re-regulation and reviewed the impact to customers resulting from Maryland's deregulation process. In addition, the Maryland PSC continues to review the relationship between Constellation Energy and BGE. Because reviews of the Maryland electric industry and market structure are ongoing, we cannot at this time predict the final outcome of these reviews and proposals or how such outcome may affect our, or BGE's, financial results, but it could be material.

In addition, the June 2006 legislation required BGE to provide credits to residential electric customers totaling approximately $39 million annually. In January 2008, we notified the State of Maryland of our intent to file a federal action to enforce our rights under the 1999 Maryland electric deregulation settlement and to challenge the constitutionality of the residential customer credits provided for under the June 2006 legislation. We may incur significant costs to litigate this action and we cannot provide any assurances that it will be resolved in our favor. If the action is resolved in a manner adverse to us, which may include a court determining that the legislation appropriately required the residential rate credits or overturning aspects of the 1999 electric deregulation settlement, the impact on our, or BGE's, financial results could be material.

The regulatory process may restrict our ability to grow earnings in certain parts of our business, cause delays in or affect business planning and transactions and increase our, or BGE's, costs.

Poor market performance will affect our benefit plan and nuclear decommissioning trust asset values, which may adversely affect our liquidity and financial results.

Our qualified pension obligations have exceeded the fair value of our plan assets since 2001. At December 31, 2007, our qualified pension obligations were approximately $315 million greater than the fair value of our plan assets. The performance of the capital markets will affect the value of the assets that are held in trust to satisfy our future obligations under our qualified pension plans. A decline in the market value of those assets may increase our funding requirements for these obligations, which may adversely affect our liquidity and financial results.

We are required to maintain funded trusts to satisfy our future obligations to decommission our nuclear power plants. A decline in the market value of those assets due to poor investment performance or other factors may increase our funding requirements for these obligations, which may have an adverse effect on our liquidity and financial results.

War and threats of terrorism and catastrophic events that could result from terrorism may impact our results of operations in unpredictable ways.

We cannot predict the impact that any future terrorist attacks may have on the energy industry in general and on our business in particular. In addition, any retaliatory military strikes or sustained military campaign may affect our operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil.

The possibility alone that infrastructure facilities, such as electric generation, electric and gas transmission and distribution facilities, would be direct targets of, or indirect casualties of, an act of terror may affect our operations.

Such activity may have an adverse effect on the United States economy in general. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our financial results or restrict our future growth. Instability in the financial markets as a result of terrorism or war may affect our stock price and our ability to raise capital.

We are subject to employee workforce factors that could affect our businesses and financial results.

We are subject to employee workforce factors, including loss or retirement of key executives or other employees, availability of qualified personnel, collective bargaining agreements with union employees, and work stoppage that could affect our financial results. In particular, our competitive energy businesses are dependent, in part, on recruiting and retaining personnel with experience in sophisticated energy transactions and the functioning of complex wholesale markets.

Our ability to successfully identify, complete and integrate acquisitions is subject to significant risks, including the effect of increased competition.

We are likely to encounter significant competition for acquisition opportunities that may become available. In addition, we may be unable to identify attractive acquisition opportunities at favorable prices and to successfully and timely complete and integrate them.

Item 2. Properties

Constellation Energy occupies approximately 900,000 square feet of leased office space in North America, which includes its corporate offices 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 owns its principal headquarters building located in downtown Baltimore. 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. The generation facilities transferred to our subsidiaries 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 expect the assets to be released from this lien following payment in March 2008 of the last series of bonds outstanding under the mortgage and the discharge of the 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.

Our merchant energy business owns several natural gas producing properties. We also lease office space in the United Kingdom and Australia to support our merchant energy business.

The following table describes our generating facilities:

Plant	Location	Capacity (MW)	% Owned	Capacit Owned (MW)	Primary Fuel
			(at December 31, 2007)		
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	963	100.0	963	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	355	100.0	355	Oil/Gas
Riverside	Baltimore Co., MD	232	100.0	232	Oil/Gas
Handsome Lake	Rockland Twp, PA	268	100.0	268	Gas
Notch Cliff	Baltimore Co., MD	120	100.0	120	Gas
Westport	Baltimore City, MD	116	100.0	116	Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor	Safe Harbor, PA	417	66.7	278	Hydro
*Total Mid-Atlantic Region **		9,376		6,355	
Plants with Power Purchase Agreements					
Nine Mile Point Unit 1	Scriba, NY	620	100.0	620	Nuclear
Nine Mile Point Unit 2	Scriba, NY	1,138	82.0	933	Nuclear
R.E. Ginna	Ontario, NY	581	100.0	581	Nuclear
Total Plants with Power Purchase Agreements		2,339		2,134	
Other					
Panther Creek	Nesquehoning, PA	80	50.0	40	Waste Coal
Colver	Colver Township, PA	104	25.0	26	Waste Coal
Sunnyside	Sunnyside, UT	51	50.0	26	Waste Coal
ACE	Trona, CA	102	31.1	32	Coal
Jasmin	Kern Co., CA	35	50.0	18	Coal
POSO	Kern Co., CA	35	50.0	18	Coal
Mammoth Lakes G-1	Mammoth Lakes, CA	6	50.0	3	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	13	50.0	7	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	13	50.0	7	Geothermal
Soda Lake I	Fallon, NV	4	50.0	2	Geothermal
Soda Lake II	Fallon, NV	10	50.0	5	Geothermal
Rocklin	Placer Co., CA	24	50.0	12	Biomass
Fresno	Fresno, CA	24	50.0	12	Biomass
Chinese Station	Jamestown, CA	20	45.0	9	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
SEGS IV	Kramer Junction, CA	33	12.2	4	Solar
SEGS V	Kramer Junction, CA	24	4.2	1	Solar
SEGS VI	Kramer Junction, CA	34	8.8	3	Solar
*Total Other **		644		239	
*Total Generating Facilities **		12,359		8,728	

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

** The sum of the individual plant capacity MWs may not equal the totals due to the effects of rounding.*

In February 2008, we acquired a partially completed 774 MW gas-fired combined-cycle power generation facility located in Alabama, which we plan to complete and have ready for commercial operation in early 2010. We discuss this acquisition in more detail in *Note 15 to Consolidated Financial Statements*.

The following table describes our processing facilities:

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

** Facility to be decommissioned in 2008.*

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	53	Chairman of the Board (since July 2002), President and Chief Executive Officer (since November 2001) of Constellation Energy	Chairman of the Board of BGE.
John R. Collins	50	Executive Vice President (since July 2007) and Chief Financial Officer (since May 2007) of Constellation Energy; Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company (since May 2007); and member of Board of Managers of Constellation Energy Partners LLC (since September 2006)	Chief Risk Officer Constellation Energy and Senior Vice President Constellation Energy.
Thomas V. Brooks	45	President of Constellation Energy Resources (since May 2007); Chairman of Constellation Energy Commodities Group, Inc. (since August 2005); and Executive Vice President of Constellation Energy (since January 2004)	Vice Chairman Constellation Energy and President and Chief Executive Officer Constellation Energy Commodities Group, Inc.
Michael J. Wallace	60	President (since January 2002) and Chief Executive Officer (since May 2005) of Constellation Energy Nuclear Group, LLC (formerly known as Constellation Generation Group, LLC); and Executive Vice President of Constellation Energy (since January 2004)	None.
Thomas F. Brady	58	Executive Vice President of Constellation Energy (since January 2004); and Chairman of the Board of BGE (since April 2007)	Senior Vice President, Corporate Strategy and Development Constellation Energy.

Irving B. Yoskowitz	62	Executive Vice President and General Counsel of Constellation Energy (since June 2005)	Senior Counsel Crowell & Moring (law firm); and Senior Partner Global Technology Partners, LLC (investment banking and consulting firm).
Felix J. Dawson	40	Co-Chief Commercial Officer of Constellation Energy Resources (since August 2007); Senior Vice President of Constellation Energy (since October 2006); Co-President and Co-Chief Executive Officer of Constellation Energy Commodities Group, Inc. (since August 2005); and President and Chief Executive Officer of Constellation Energy Partners LLC (since May 2006)	Co-Chief Commercial Officer Constellation Energy Commodities Group, Inc.; and Managing Director Constellation Energy Commodities Group, Inc.
George E. Persky	38	Co-Chief Commercial Officer of Constellation Energy Resources (since August 2007); Senior Vice President of Constellation Energy (since October 2006); and Co-President and Co-Chief Executive Officer of Constellation Energy Commodities Group, Inc. (since August 2005)	Co-Chief Commercial Officer Constellation Energy Commodities Group, Inc.; and Managing Director Constellation Energy Commodities Group, Inc.
Kenneth W. DeFontes, Jr.	57	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.
Paul J. Allen	56	Senior Vice President, Corporate Affairs (since January 2004) and Chief Environmental Officer (since June 2007) of Constellation Energy	Vice President, Corporate Affairs Constellation Energy.
Beth S. Perlman	47	Senior Vice President (since January 2004), Chief Administrative Officer (since June 2007) and Chief Information Officer (since April 2002) of Constellation Energy	Vice President Constellation Energy.
Marc L. Ugol	49	Senior Vice President, Human Resources of Constellation Energy (since January 2004)	Vice President, Human Resources Constellation Energy.

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, Related Shareholder Matters and Issuer Purchases of Equity Securities

Stock Trading

Constellation Energy's common stock is traded under the ticker symbol CEG. It is listed on the New York and Chicago stock exchanges.

As of January 31, 2008, there were 39,186 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 2008, we announced an increase in our quarterly dividend from $0.435 to $0.4775 per share payable April 1, 2008 to holders of record on March 10, 2008. This is equivalent to an annual rate of $1.91 per share.

Quarterly dividends were declared on our common stock during 2007 and 2006 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

	2007			2006		
		Price			Price	
	Dividend Declared	High	Low	Dividend Declared	High	Low
First Quarter	$ 0.435	$ 88.20	$ 68.78	$ 0.3775	$ 60.55	$ 54.01
Second Quarter	0.435	95.57	82.71	0.3775	55.68	50.55
Third Quarter	0.435	98.20	76.64	0.3775	60.79	53.70
Fourth Quarter	0.435	104.29	85.81	0.3775	70.20	59.00
Total	$ 1.74			$ 1.51		

Purchases of Equity Securities by the Issuer and Affiliated Purchases

The following table discloses purchases of shares of our common stock made by us or on our behalf for the periods shown below.

Period	Total Number of Shares Purchased(1)	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Amount of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)(2)
October 1 October 31, 2007		$		$ 1.0 billion
November 1 November 30, 2007	200,000	96.31	2,023,527(3)	750 million
December 1 December 31, 2007	250,218	103.24		750 million
Total	450,218	$ 100.16	2,023,527	

(1) Represents shares surrendered by employees to exercise stock options and to satisfy tax withholding obligations on vested restricted stock and stock option exercises and shares repurchased by us in the open market to satisfy employee stock option exercises and restricted stock grants.

(2) In October 2007, our board of directors approved a common share repurchase program for up to $1 billion of our outstanding common shares. The program is expected to be executed over the 24 months following approval in a manner that preserves flexibility to pursue additional strategic investment opportunities.

(3) Represents shares repurchased pursuant to an accelerated share repurchase agreement entered into with a financial institution. The final price of the shares repurchased was determined based on a discount to the volume-weighted average trading price of $100.53 per share of our common stock. In January 2008, the financial institution delivered 514,376 additional shares to us at the completion of the transaction.

See *Note 9 to Consolidated Financial Statements* for a further description of our common share repurchase program and the accelerated share repurchase agreement.

Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2007	2006	2005	2004	2003
			(In millions, except per share amounts)		
Summary of Operations					
Total Revenues	**$ 21,193.2**	$ 19,284.9	$ 16,968.3	$ 12,127.2	$ 9,342.8
Total Expenses	**19,858.8**	18,025.2	16,023.8	11,209.1	8,395.5
Gain on Sale of Gas-Fired Plants		73.8			
Income From Operations	**1,334.4**	1,333.5	944.5	918.1	947.3
Gain on sales of CEP equity	**63.3**	28.7			
Other Income	**158.6**	66.1	65.5	25.5	20.6
Fixed Charges	**305.6**	328.7	310.2	326.8	336.3
Income Before Income Taxes	**1,250.7**	1,099.6	699.8	616.8	631.6
Income Taxes	**428.3**	351.0	163.9	118.4	222.2
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**822.4**	748.6	535.9	498.4	409.4
(Loss) Income from Discontinued Operations, Net of Income Taxes	**(0.9)**	187.8	94.4	41.3	66.3
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes			(7.2)		(198.4)
Net Income	**$ 821.5**	$ 936.4	$ 623.1	$ 539.7	$ 277.3
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Assuming Dilution	**$ 4.51**	$ 4.12	$ 2.98	$ 2.88	$ 2.45
(Loss) Income from Discontinued Operations	**(0.01)**	1.04	0.53	0.24	0.40
Cumulative Effects of Changes in Accounting Principles			(0.04)		(1.19)
Earnings Per Common Share Assuming Dilution	**$ 4.50**	$ 5.16	$ 3.47	$ 3.12	$ 1.66
Dividends Declared Per Common Share	**$ 1.74**	$ 1.51	$ 1.34	$ 1.14	$ 1.04
Summary of Financial Condition					
Total Assets	**$ 21,945.7**	$ 21,801.6	$ 21,473.9	$ 17,347.1	$ 15,593.0
Current Portion of Long-Term Debt	**$ 380.6**	$ 878.8	$ 491.3	$ 480.4	$ 343.2
Capitalization					
Long-Term Debt	**$ 4,660.5**	$ 4,222.3	$ 4,369.3	$ 4,813.2	$ 5,039.2
Minority Interests	**19.2**	94.5	22.4	90.9	113.4

	2007	2006	2005	2004	2003
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**5,340.2**	4,609.3	4,915.5	4,726.9	4,140.5
Total Capitalization	**$ 10,209.9**	$ 9,116.1	$ 9,497.2	$ 9,821.0	$ 9,483.1
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**3.84**	4.05	3.04	2.71	2.69
Book Value Per Share of Common Stock	**$ 29.93**	$ 25.54	$ 27.57	$ 26.81	$ 24.68

We discuss items that affect comparability between years, including acquisitions and dispositions, accounting changes and other items, in *Item 7. Management's Discussion and Analysis*.

Baltimore Gas and Electric Company and Subsidiaries

	2007	2006	2005	2004	2003
			(In millions)		
Summary of Operations					
Total Revenues	**$ 3,418.5**	$ 3,015.4	$ 3,009.3	$ 2,724.7	$ 2,647.6
Total Expenses	**3,084.2**	2,646.3	2,612.8	2,353.3	2,262.6
Income From Operations	**334.3**	369.1	396.5	371.4	385.0
Other Income (Expense)	**26.8**	6.0	5.9	(6.4)	(5.4)
Fixed Charges	**125.3**	102.6	93.5	96.2	111.2
Income Before Income Taxes	**235.8**	272.5	308.9	268.8	268.4
Income Taxes	**96.0**	102.2	119.9	102.5	105.2
Net Income	**139.8**	170.3	189.0	166.3	163.2
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Earnings Applicable to Common Stock	**$ 126.6**	$ 157.1	$ 175.8	$ 153.1	$ 150.0
Summary of Financial Condition					
Total Assets	**$ 5,783.0**	$ 5,140.7	$ 4,742.1	$ 4,662.9	$ 4,706.6
Current Portion of Long-Term Debt	**$ 375.0**	$ 258.3	$ 469.6	$ 165.9	$ 330.6
Capitalization					
Long-Term Debt	**$ 1,862.5**	$ 1,480.5	$ 1,015.1	$ 1,359.5	$ 1,343.7
Minority Interest	**16.8**	16.7	18.3	18.7	18.9
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,671.7**	1,651.5	1,622.5	1,566.0	1,487.7
Total Capitalization	**$ 3,741.0**	$ 3,338.7	$ 2,845.9	$ 3,134.2	$ 3,040.3
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**2.84**	3.60	4.22	3.75	3.36
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**2.42**	2.99	3.45	3.08	2.82

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

Introduction and Overview

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries including a merchant energy business and Baltimore Gas and Electric Company (BGE). We describe our operating segments in *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 and the risk factors affecting our business in *Item 1A. Risk Factors* 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 2007, 2006, and 2005. 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 providing 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 purchases and sales of energy, capacity, and related products to various customers, including distribution utilities, municipalities, cooperatives, and industrial, commercial, and governmental customers.

We obtain this energy through both owned and contracted supply resources. Our generation fleet is strategically located in deregulated markets and includes various fuel types, such as nuclear, coal, gas, oil, and renewable sources. In addition to owning generating facilities, we contract for power from other merchant providers, typically through power purchase agreements. We will use both our owned generation and our contracted generation to support our competitive supply operations.

In addition, our merchant energy business is active in both upstream and downstream natural gas areas as well as coal sourcing and logistics services for the variable and fixed supply needs of global customers.

We are a leading national competitive supplier of energy. 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 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.

We trade energy and energy-related commodities and deploy risk capital in the management of our portfolio in order to earn additional returns. These activities are managed through daily value at risk and stop loss limits and liquidity guidelines.

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, risk management, and trading 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, risk management, and trading operation by providing a source of reliable power supply.

To achieve our strategic objectives, we expect to continue to pursue opportunities that expand our access to customers and to support our wholesale marketing, risk management, and trading operation with generation assets that have diversified geographic, fuel, and dispatch characteristics. We also expect to grow through buying and 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, customer satisfaction and customer demand response initiatives.

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 and gas properties to support our merchant energy business,
- renovating or extending the life of existing generation facilities,
- mergers or acquisitions of utility or non-utility businesses or assets, and
- sale of assets of one or more businesses.

Business Environment

With the evolving regulatory environment surrounding customer choice, increasing competition, and the growth of our merchant energy business, various factors affect our financial results. We discuss some of these factors in more detail in the *Item 1. Business Competition* section. We also discuss these various factors in the *Forward Looking Statements* and *Item 1A. Risk Factors* sections.

Over the last several years, the energy markets have been highly volatile with significant changes in natural gas, power, oil, coal, and emission allowance prices. The volatility of the energy markets impacts our credit portfolio, and 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.

In addition, the volatility of the energy markets impacts our liquidity and collateral requirements. We discuss our liquidity in the *Financial Condition* section.

Competition

We face competition in the sale of electricity, natural gas, and coal in wholesale energy markets and to retail customers.

Various states have moved to restructure their retail electricity and gas 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 to support or expand 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.

Specifically, legislatures in a number of states are considering, to varying degrees, legislation currently to either eliminate or expand retail choice programs. In addition, many states have initiated proceedings to reconsider the method of wholesale procurement for meeting their utilities' default/provider-of-last-resort requirements. Both the reconsideration of retail choice and possible new methodologies for wholesale procurement could affect our customer supply group's future opportunities to service commercial and industrial customers and the ability to provide wholesale products to utilities. The outcome of these efforts cannot be predicted, but they could have a material effect on our financial results.

All BGE electricity and gas customers have the option to purchase electricity and gas from alternate suppliers.

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 Baltimore Gas and Electric Company Electric Business Electric Competition* section.

Regulation Maryland

Maryland PSC

In addition to electric restructuring, which is discussed in *Item 1. Business Electric Competition section*, regulation by the Maryland PSC significantly influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers of its electric distribution and gas businesses. The Maryland PSC incorporates into BGE's standard offer service 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), 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.

Senate Bills 1 and 400

In June 2006, Senate Bill 1 was enacted, which among other things:

- imposed rate stabilization measures that (i) capped rate increases by BGE for residential SOS service at 15% from July 1, 2006 to May 31, 2007, (ii) gave residential SOS customers the option from June 1, 2007 until December 31, 2007 of paying a full market rate or choosing a short term rate stabilization plan in order to provide a smooth transition to market rates without adversely affecting the creditworthiness of BGE, and (iii) provided for full market rates for all residential SOS service starting January 1, 2008;

- allowed BGE to recover the costs deferred from July 1, 2006 to May 31, 2007 from its customers over a period not to exceed 10 years, on terms and conditions to be determined by the Maryland PSC, including through the issuance of rate stabilization bonds that securitize the deferred costs; and

- required BGE to reduce residential electric rates by approximately $39 million per year for 10 years, beginning January 1, 2007, through suspension of the collection of the residential return component of the administrative charge for SOS service through May 31, 2007 and by providing to all residential electric customers a credit equal to the amounts collected from all BGE customers for the nuclear decommissioning trust for Calvert Cliffs. We provide further details in *Item 1. Business Cost for Decommissioning Nuclear Facilities* section and in *Item 7. Management's Discussion and Analysis Regulated Electric Business Senate Bill 1 Credits* section.

In connection with these provisions of Senate Bill 1:

In May 2007, the Maryland PSC approved a plan to allow residential electric customers to defer the transition to full market rates from June 1, 2007 to January 1, 2008. The 4 percent of customers who chose to defer will repay the deferred amounts over a twenty-one month period starting April 1, 2008 without interest.

In June 2007, a subsidiary of BGE issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover costs relating to the residential rate deferral from July 1, 2006 to May 31, 2007. We discuss the rate stabilization bond issuance in more detail in *Note 9*.

In June 2007, the Maryland PSC required BGE to reinstate collection of the residential return component of the POLR administration charge in POLR rates and to provide all residential electric customers a credit for the residential return component of the administrative charge.

In connection with implementing the approximately $39 million in credits to residential electric customers discussed above, BGE and Calvert Cliffs had notified the Maryland PSC that they had entered into a standstill agreement with the Attorney General of the State of Maryland with respect to potential challenges to the provisions of Senate Bill 1 relating to the credits. In January 2008, BGE and Calvert Cliffs provided the Attorney General with notice of their termination of the standstill agreement and their intent to file a federal action to enforce their rights under the 1999 Maryland electric deregulation settlement and to challenge the constitutionality of the residential customer credits set forth in Senate Bill 1. We may incur significant costs to litigate this action and we cannot provide any assurances that it will be resolved in our favor. If the action is resolved in a manner adverse to us, which may include a court determining that Senate Bill 1 appropriately required the residential rate credits or overturning aspects of the 1999 electric deregulation settlement, the impact on our, or BGE's, financial results could be material.

Further, in April 2007, Senate Bill 400 was enacted, which made certain modifications to Senate Bill 1. Pursuant to Senate Bill 400, the Maryland PSC was required to initiate several studies, including studies relating to stranded costs, the costs and benefits of various options for reregulation, and the structure of the electric industry in Maryland. In addition, the Maryland PSC has indicated that they are studying the relationship between Constellation Energy and BGE.

In December 2007, the Maryland PSC issued an interim report addressing the costs and benefits of various options for reregulation and recommending actions to be taken to address an anticipated shortage of generation and transmission capacity in Maryland, which included implementation of demand response initiatives and requiring utilities to enter into long-term power purchase contracts with suppliers.

In January 2008, the Maryland PSC issued another interim report that indicated that the Maryland PSC would initiate proceedings into payments made by BGE customers for stranded costs resulting from BGE's transfer of generation assets to certain Constellation Energy affiliates in connection with deregulation and into Constellation Energy's management of its nuclear decommissioning funds. This interim report also recommended that the Maryland legislature enact legislation to provide the Maryland PSC with the authority to regulate nuclear decommissioning funds and consider legislation that would provide the Maryland PSC with the authority to consider reallocation of the liability for nuclear decommissioning among Constellation Energy, BGE and customers or to otherwise order relief for customers. Similarly, the interim report also recommended that the Maryland legislature consider legislation to order relief for customers depending on the outcome of the Maryland PSC's stranded cost proceeding.

The Maryland PSC is required to issue a final report in December 2008. We cannot at this time predict the ultimate outcome of these inquiries, studies, and recommendations or their actual effect on our, or BGE's financial results, but it could be material. In addition, one or more parties may challenge in court one or more provisions of Senate Bills 1 and 400. The outcome of any challenges and the uncertainty that could result cannot be predicted.

We discuss the market risk of our regulated electric business in more detail in the *Market Risk* section.

Base Rates

Base rates are the rates the Maryland PSC allows BGE to charge its customers for the cost of providing them delivery service, plus a profit. BGE has both electric base rates and gas base rates. 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. In 2008, BGE plans to file a combination electric and gas base rate case. The Maryland PSC historically has allowed BGE to increase base rates to recover its utility plant investment and operating costs, plus a profit. 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.

BGE's most recently approved return on electric distribution rate base was 9.4% (approved in 1993). BGE's most recently approved return on gas rate base was 8.49% (approved in 2005).

In December 2005, the Maryland PSC issued an order granting BGE a $35.6 million annual increase in its gas base rates. In December 2006, the Baltimore City Circuit Court upheld the rate order. However, certain parties have filed an appeal with the Court of Special Appeals. We cannot provide assurance that the Maryland PSC's order will not be reversed in whole or part or that certain issues will not be remanded to the Maryland PSC for reconsideration.

Revenue Decoupling

Beginning in 2008, BGE will record a monthly adjustment to its electric distribution revenues from residential and small commercial customers to eliminate the effect of abnormal weather and usage patterns per customer on its electric distribution volumes in accordance with Maryland PSC requirements. This means that BGE's monthly electric distribution revenues from residential and small commercial customers will be based on weather and usage that is considered normal for the month. Therefore, these revenues are affected by customer growth and will not be affected by actual weather or usage conditions. We have a similar revenue decoupling mechanism in our gas business.

Demand Response and Advanced Metering Programs

In order to implement advanced metering and demand response programs, BGE will defer costs associated with these programs as a regulatory asset and recover these costs from customers in future periods. We discuss the advanced metering and demand response programs in more detail in *Item 1. Business Baltimore Gas and Electric Company Electric Load Management*.

Electric Commodity and Transmission Charges

BGE electric commodity and transmission charges (standard offer service), including the impact of the enactment of Senate Bill 1 in Maryland, are discussed in *Business Environment Regulation Maryland Senate Bills 1 and 400* 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 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 electric transmission and wholesale natural gas and electricity sales. BGE transmission rates are updated annually based on a formula methodology approved by FERC. The rates also include transmission investment incentives approved by FERC in orders issued in July and November of 2007. We believe that FERC's continued commitment to fair and efficient wholesale energy markets should continue to result in improvements to competitive markets across various regions.

Since 1997, operation of BGE's transmission system has been under the authority of PJM Interconnection (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. The liability of transmission owners, including BGE, and power generators is limited to those damages caused by the gross negligence of such entities.

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 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 by FERC. We cannot predict the outcome of any reviews at this time. However, changes to the structure of these markets could have a material effect on our financial results.

Ongoing initiatives at FERC have included a review of its methodology for the granting of market-based rate authority to sellers of electricity. FERC has established 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, FERC may require companies to implement measures to mitigate the market power in order to maintain market-based rate authority. We believe that our entities selling wholesale power continue to satisfy FERC's test for determining whether to grant a public utility market-based rate authority.

In November 2004, FERC eliminated through and out transmission rates between the Midwest Independent System Operator (MISO) and PJM and put in place Seams Elimination Charge/Cost Adjustment/Assignment (SECA) transition rates, which are paid by the transmission customers of MISO and PJM and allocated among the various transmission owners in PJM and MISO. The SECA transition rates were in effect from December 1, 2004 through March 31, 2006. FERC set for hearing the various compliance filings that established the level of the SECA rates and has indicated that the SECA rates are being recovered from the MISO and PJM transmission customers subject to refund by the MISO and PJM transmission owners.

We are a recipient of SECA payments, payer of SECA charges, and supplier to whom such charges may be shifted. Administrative hearings regarding the SECA charges concluded in May 2006, and an initial decision from the FERC administrative law judge (ALJ) was issued in August 2006. The decision of the ALJ generally found in favor of reducing the overall SECA liability. The decision, if upheld, is expected to significantly reduce the overall SECA liability at issue in this proceeding. However, the ALJ also allowed SECA charges to be shifted to upstream suppliers, subject to certain adjustments. Therefore, certain charges could be shifted to our wholesale marketing, risk management, and trading operation. This decision will be reviewed by FERC. We are unable to predict the timing or final outcome of FERC's SECA rate proceeding. However, as the amounts collected under the SECA rates are subject to refund and the ultimate outcome of the proceeding establishing SECA rates is uncertain, the result of this proceeding may have a material effect on our financial results.

In April 2006, FERC issued an initial order approving PJM's proposal to restructure its capacity market, which establishes the method by which we are paid for making generating plant capacity available to PJM. The capacity market or Reliability Pricing Model (RPM) was approved by FERC in December 2006 after settlement proceedings. FERC in June and November 2007 upheld the RPM settlement in response to requests for rehearing. An appeal of FERC's decisions on RPM was filed in January 2008 in the United States Court of Appeals for the District of Columbia Circuit. Currently, we cannot predict with certainty what effect the results of these challenges will have on our, or BGE's, financial results.

Also in January 2008 in connection with RPM, PJM filed revisions to its capacity market rules to reflect increased construction costs for new entry of generation (CONE). CONE is used in determining the price paid to capacity resources that clear in the PJM capacity auction. The outcome of this pending filing at FERC is uncertain, but it could have a material effect on our financial results.

Three major, high-voltage transmission lines have been announced that could enhance significantly the transfer capacity of the PJM transmission system from west to east. The siting process either in the states or at FERC is uncertain, as is the likelihood that one or more of the transmission lines will be ultimately constructed. The construction of the transmission lines, which could depress both capacity and energy prices for generation located in Maryland and elsewhere in the eastern part of PJM, could have a material effect on our financial results.

Other market changes are routinely proposed and considered on an ongoing basis. 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.

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, gas, 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 has approved revenue decoupling mechanisms which allow BGE to record monthly adjustments to our regulated electric and gas business distribution revenues to eliminate the effect of abnormal weather and usage patterns. We discuss this further in the *Regulation Maryland PSC Revenue Decoupling* and *Regulated Gas Business Gas Revenue Decoupling* sections.

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 supply and 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.

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*.

Accounting for Derivatives

Our merchant energy business originates and acquires 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. The accounting requirements for derivatives are governed by Statement of Financial Accounting Standard (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, and applying those requirements involves the exercise of judgment in evaluating these provisions, as well as related implementation guidance and applying those requirements to complex contracts in a variety of commodities and markets. We record all derivatives subject to the accounting requirements of SFAS No. 133 as "Derivative assets or liabilities" in our Consolidated Balance Sheets. Within derivative assets and liabilities, we include derivative contracts subject to mark-to-market accounting and derivative contracts that qualify for designation as hedges under SFAS No. 133.

Many fundamental customer contracts in our business, such as those associated with our load-serving activities, must be accounted for on an accrual basis. We may economically hedge these contracts with derivatives and elect cash-flow hedge accounting or apply the normal purchase and normal sale exception in order to match more closely the timing of the recognition of earnings from these transactions. We make these elections because we believe that accrual accounting provides the most transparent presentation to our shareholders of these business activities. If our commercial transactions or related hedges meet the definition of a derivative, we must comply with the provisions of SFAS No. 133 in order to use cash-flow hedge accounting or the normal purchase and normal sale exception. Qualifying for either of these accounting treatments requires ongoing compliance with specific, detailed documentation and other requirements that may be unrelated to the economics of the transactions or how the associated risks are managed. While we believe we have appropriate controls in place to comply with these requirements, the failure to meet all of those requirements, even inadvertently, may result in disqualifying the use of these accounting treatments for those transactions for any affected period until all such requirements are satisfied.

The exercise of management's judgment in using cash-flow hedge accounting or electing the normal purchase and sale exception versus mark-to-market accounting, including compliance with all of the associated qualification and documentation requirements, materially impacts our financial results with respect to timing of the recognition of earnings. In addition, interpretations of SFAS No. 133 could continue to evolve. If there is a future change in interpretation or a failure to meet the qualification and documentation requirements, contracts that currently are excluded from the provisions of SFAS No. 133 under the normal purchase and normal sale exception or for which changes in fair value are recorded in other comprehensive income under cash-flow hedge accounting could be deemed to no longer qualify for those accounting treatments. If that were to occur, normal purchase and normal sale contracts could be required to be recorded on the balance sheet at fair value with changes in value recorded in the income statement, and changes in value of derivatives previously designated as cash-flow hedges could be required to be recorded in the income statement rather than in other comprehensive income.

We record revenues and fuel and purchased energy expenses from the sale or purchase of energy, energy-related products, and energy services under the accrual method of accounting in the period when we deliver or receive energy commodities, products, and 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. 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. While we generally elect accrual accounting whenever permitted, we sometimes use mark-to-market accounting for physical delivery activities that are managed using economic hedges that do not qualify for accrual accounting.

The use of accrual accounting requires us to analyze contracts to determine whether they are non-derivatives or, if they are derivatives, whether they meet the requirements for designation as normal purchases and normal sales. For those derivative contracts that do not meet these criteria, we may also analyze whether they qualify for hedge accounting, including performing an evaluation of historical forward market price information to determine whether such contracts are expected to be highly effective in offsetting changes in cash flows from the risk being hedged.

We use the mark-to-market method of accounting for derivative contracts for which we do not elect 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 assets and liabilities at the time of contract execution. We record the changes in these derivative assets and liabilities in our Consolidated Statements of Income.

Derivative assets and liabilities accounted for under the mark-to-market method of accounting 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 the related derivative 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 these derivative 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. As discussed below and more fully in *Note 1*, our valuation adjustments will be affected by the adoption of SFAS No. 157, *Fair Value Measurements*, in 2008.

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. Prior to the adoption of SFAS No. 157 on January 1, 2008, 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.

Unobservable input valuation adjustment upon adoption of SFAS No. 157, this adjustment is necessary when we are required to determine fair value for derivative positions using internally developed models that use unobservable inputs due to the absence of observable market information. Unobservable inputs to fair value may arise due to a number of factors, including but not limited to, the term of the transaction, contract optionality, delivery location, or product type. In the absence of observable market information that supports the model inputs, there is a presumption that the transaction price is equal to the market value of the contract when we transact in our principal market and SFAS No. 157 requires us to recalibrate our estimate of fair value to equal the transaction price. Therefore we do not recognize a gain or loss at contract inception on these transactions. We will 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 derivative 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 derivative 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. Upon adoption of SFAS No. 157, we will also use a credit-spread adjustment in order to reflect our own credit risk in determining the fair value of our derivative liabilities.

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.

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

- our ability to continue to designate and qualify derivative contracts for normal purchase and normal sale accounting or hedge accounting under the requirements of SFAS No. 133, as amended and as interpreted in supplemental guidance,
- potential volatility in earnings from ineffectiveness associated with derivatives subject to hedge accounting,
- potential volatility in earnings from derivative contracts that serve as economic hedges for which we do not elect or do not meet the accounting requirements to qualify for normal purchase and normal 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.

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 legislature or an adverse change 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 at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. This necessarily requires us to estimate uncertain future cash flows.

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

Gas Properties

We evaluate unproved property at least annually to determine if it is impaired under SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Properties*. Impairment for unproved property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance.

Debt and Equity Securities

Our investments in debt and equity securities, primarily our nuclear decommissioning trust fund assets, are subject to impairment evaluations under FASB Staff Positions SFAS 115-1 and SFAS 124-1 (FSP 115-1 and 124-1), *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments.* FSP 115-1 and 124-1 require us to determine whether a decline in fair value of an investment below book value 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. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value for these securities is considered other than temporary and must be written down to fair value.

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

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 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.

In view of the significant number of assumptions underlying the decommissioning cost estimate, our estimate of the future cost of decommissioning is likely to continue to change over time. For perspective, a 10% increase or decrease in our estimate of the future cost of decommissioning would produce an approximately $80 million change to our asset retirement obligation and an approximately $10 million change in our total annual amortization and accretion expenses.

Significant Events

Common Share Repurchase Program

In October 2007, our board of directors approved a common share repurchase program for up to $1 billion of our outstanding common stock. We discuss this common share repurchase program in more detail in *Note 9*.

Dividend Increase

In January 2008, we announced an increase in our quarterly dividend to $0.4775 per share on our common stock. This is equivalent to an annual rate of $1.91 per share. Previously, our quarterly dividend on our common stock was $0.435 per share, equivalent to an annual rate of $1.74 per share.

CEP

CEP, a limited liability company formed in 2006 by Constellation Energy, issued additional equity to the public in 2007. As a result, in the second quarter of 2007, our ownership percentage in CEP fell below 50 percent, and we deconsolidated CEP and began accounting for our investment using the equity method of accounting.

We discuss the issuances of CEP's equity and their impact on our financial results in more detail in *Note 2*.

Acquisitions

During 2007, we acquired working interests in gas and oil producing fields, and an entity that expanded our retail competitive supply operations. In February 2008, we acquired a partially completed 774 MW gas-fired combined-cycle power generation facility located in Alabama. We discuss these acquisitions in more detail in the *Note 15*.

We also acquired a portfolio of energy contracts during 2007. We discuss these energy contracts in more detail in the *Financial Condition* section.

Shipping Joint Venture

During 2007, we made cash contributions totaling $57 million to a shipping joint venture in which we have a 50% ownership interest. We discuss this joint venture in more detail in *Note 4*.

Electricite de France Joint Venture

In August 2007, we formed a joint venture, UniStar Nuclear Energy, LLC (UNE) with an affiliate of Electricite de France, SA (EDF). We discuss this joint venture in more detail in *Note 4*.

Rate Stabilization Bonds

In 2007, BGE formed a special purpose bankruptcy-remote limited liability company to purchase rate stabilization property from BGE and to issue rate stabilization bonds. We discuss this entity and the related financing in more detail in *Note 4* and *Note 9*.

Synthetic Fuel Facilities

Our merchant energy business has investments in facilities that manufacture solid synthetic fuel produced from coal as defined under the Internal Revenue Code (IRC) for which we can claim tax credits on our Federal income tax return through 2007. The IRC provides for a phase-out of synthetic fuel tax credits if average annual wellhead oil prices increase above certain levels. For 2007, we estimate the tax credit reduction would begin if the reference price exceeds approximately $56 per barrel and would be fully phased-out if the reference price exceeds approximately $71 per barrel. Based on monthly EIA published wellhead oil prices for the ten months ended October 31, 2007 and November and December NYMEX prices for light, sweet, crude oil (adjusted for the 2007 difference between EIA and NYMEX prices), we estimate a 70% tax credit phase-out in 2007. We recorded the effect of this phase-out estimate as a reduction in tax credits of $110.3 million during 2007. We discuss how we determine the amount of phase-out in more detail in *Note 10*.

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Results of Operations

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, and 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

	2007	2006	2005
		(In millions, after-tax)	
Merchant energy	**$ 679.2**	$ 580.1	$ 359.4
Regulated electric	**97.9**	120.2	149.4
Regulated gas	**28.8**	37.0	26.7
Other nonregulated	**16.5**	11.3	0.4
Income from continuing operations and before cumulative effects of changes in accounting principles	**822.4**	748.6	535.9
(Loss) income from discontinued operations	**(0.9)**	187.8	94.4
Cumulative effects of changes in accounting principles			(7.2)
Net Income	**$ 821.5**	$ 936.4	$ 623.1
Other Items Included in Operations (after-tax)			
Gain on sale of gas-fired plants	**$**	$ 47.1	$
Non-qualifying hedges	**2.0**	39.2	(24.9)
Impairment losses and other costs	**(12.2)**		
Workforce reduction costs	**(1.4)**	(17.0)	(2.6)
Merger-related costs		(5.7)	(15.6)
Total Other Items	**$ (11.6)**	$ 63.6	$ (43.1)

2007

Our total net income for 2007 decreased $114.9 million, or $0.66 per share, compared to 2006 mostly because of the following:

We had lower earnings from discontinued operations of $188.7 million after-tax mostly due to the absence of the gain on sale of our High Desert facility in 2006. In addition, we had lower earnings of $47.1 million after-tax resulting from the recognition of a gain on sale of five other gas-fired generating facilities in 2006. We discuss the sale of these plants in more detail in *Note 2*.

We had lower earnings of $34.0 million after-tax at our synthetic fuel processing facilities mostly due to a higher phase-out of tax credits. We discuss synthetic fuel tax credits in more detail in *Note 10*.

We had lower earnings of $30.5 million after-tax at our regulated businesses primarily due to the impact of residential credits required by Senate Bill 1 and higher operations and maintenance expenses. We discuss Senate Bill 1 in more detail in *Business Environment Regulation Maryland Senate Bills 1 and 400* section.

We had lower earnings of $9.3 million after-tax at our retail competitive supply operation due primarily to higher operating expenses, partially offset by higher gross margin. We discuss our retail gross margin in more detail in the *Competitive Supply* section.

We had lower earnings due to a $12.2 million after-tax charge related to a cancelled wind development project. We discuss this charge in more detail in *Note 2*.

We had lower earnings of approximately $6 million after-tax at our wholesale competitive supply operation due to higher expenses and the absence of income from our gas plants that were sold in December 2006, mostly offset by higher gross margin. We discuss our mark-to-market and wholesale accrual results in more detail in the *Competitive Supply* section.

These decreases were partially offset by the following:

We had higher earnings of approximately $98 million after-tax at our merchant energy business due to higher gross margin from the Mid-Atlantic Region. We discuss this increase in gross margin in more detail in the *Mid-Atlantic Region* section.

We had higher earnings of approximately $70 million after-tax from an increase in other income mostly due to interest income resulting from a higher cash balance primarily from proceeds from the sale of gas-fired plants in December 2006, and lower fixed charges due to the repayment of $600 million of long-term debt in April 2007.

We had higher earnings of approximately $21 million after-tax due to gains on the sales of equity by CEP. We discuss these sales in more detail in *Note 2*.

We had higher earnings of $15.6 million after-tax related to lower workforce reduction costs.

We had higher earnings of $5.7 million after-tax due to the absence of merger-related costs associated with our cancelled merger with FPL Group.

2006

Our total net income for 2006 increased $313.3 million, or $1.69 per share, compared to 2005 mostly because of the following:

We had higher earnings of approximately $144 million after-tax at our merchant energy business due to higher gross margin from the Mid-Atlantic Region. We discuss this increase in gross margin in more detail in the *Mid-Atlantic Region* section.

We had higher earnings from discontinued operations of $93.4 million after-tax mostly due to the gain on sale of our High Desert facility. In addition, we had higher earnings of $47.1 million after-tax resulting from the recognition of a gain on sale of five other gas-fired generating facilities. We discuss the sale of these plants in more detail in *Note 2*.

We had higher wholesale competitive supply gross margin of approximately $105 million after-tax. This increase was partially offset by approximately $68 million after-tax of higher operating expenses mostly because of higher labor and benefit costs due to the growth of our wholesale competitive supply operation. We discuss our mark-to-market and wholesale accrual results in more detail in the *Competitive Supply* section.

We had higher earnings of $67.7 million after-tax at our retail competitive supply operation primarily due to an increase in gross margin, partially offset by higher operating expenses to support the growth of this operation. We discuss our retail gross margin in more detail in the *Competitive Supply Retail* section.

We had higher earnings of approximately $18 million after-tax due to the gain on the CEP initial public offering. This gain was partially offset by cash-flow hedge losses of approximately $10 million after-tax reclassified from "Accumulated other comprehensive income" to revenues as a result of the initial public offering. We discuss the CEP transaction in more detail in *Note 2*.

We had higher earnings of $10.3 million after-tax from our regulated gas business primarily due to the favorable impact of the increase in gas base rates that was approved in December 2005.

These increases were partially offset by the following:

We had lower earnings of $30.1 million after-tax at our synthetic fuel facilities mostly due to the expected phase-out of tax credits as a result of the high price of oil. We discuss the phase-out of tax credits in more detail in *Note 10*.

We had lower earnings of $29.2 million after-tax from our regulated electric business primarily due to higher operations and maintenance expenses and lower revenues less electricity purchased for resale expenses.

We had lower earnings of $14.4 million after-tax due to workforce reduction costs associated with workforce restructurings at our nuclear generating facilities. We discuss these costs in more detail in *Note 2*.

We had lower earnings of approximately $11 million after-tax due to higher fixed charges and lower other income. We discuss these items in more detail in the *Consolidated Nonoperating Income and Expenses* section.

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.

Our merchant energy business focuses on delivery of physical, customer-oriented products to producers and consumers, manages the risk and optimizes the value of our owned generation assets, and uses our portfolio management and trading capabilities both to manage risk and to deploy risk capital to generate additional returns. We continue to identify and pursue opportunities which can generate additional returns through portfolio management and trading activities within our business. These opportunities have increased due to the significant growth in scale of our competitive supply operations.

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 revenue and expense recognition 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 or fuel and purchased energy expenses in the period in which the change occurs.

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

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

Results

	2007	2006	2005
		(In millions)	
Revenues	$ **18,744.5**	$ 17,166.2	$ 14,622.4
Fuel and purchased energy expenses	**(15,501.8)**	(14,256.3)	(12,301.8)
Operating expenses	**(1,791.8)**	(1,549.4)	(1,346.1)
Impairment losses and other costs	**(20.2)**		
Workforce reduction costs	**(2.3)**	(28.2)	(4.4)
Merger-related costs		(13.1)	(11.2)
Depreciation, depletion, and amortization	**(269.9)**	(258.7)	(250.4)
Accretion of asset retirement obligations	**(68.3)**	(67.6)	(62.0)
Taxes other than income taxes	**(110.2)**	(120.0)	(106.7)
Gain on sale of gas-fired plants		73.8	
Income from Operations	$ **980.0**	$ 946.7	$ 539.8
Income from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	$ **679.2**	$ 580.1	$ 359.4
(Loss) Income from discontinued operations (after-tax)	**(0.9)**	186.9	73.8
Cumulative effects of changes in accounting principles (after-tax)			(7.4)
Net Income	$ **678.3**	$ 767.0	$ 425.8
Other Items Included in Operations (after-tax)			
Gain on sale of gas-fired plants	$	$ 47.1	$
Non-qualifying hedges	**2.0**	39.2	(24.9)
Impairment losses and other costs	**(12.2)**		
Workforce reduction costs	**(1.4)**	(17.0)	(2.6)
Merger-related costs		(4.3)	(10.4)
Total Other Items	$ **(11.6)**	$ 65.0	$ (37.9)

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.

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. As previously discussed, our merchant energy business uses either accrual or mark-to-market accounting to record our revenues and expenses. Mark-to-market results reflect the net impact of amounts recorded in either revenues or fuel and purchased energy expenses to recognize changes in fair value of derivative contracts subject to mark-to-market accounting during the reporting period.

The difference between revenues and fuel and purchased energy expenses, including all direct expenses, is the gross margin of our merchant energy business, and this measure is a useful tool for assessing the profitability of our merchant energy business. Accordingly, we believe it is appropriate to discuss the operating results of our merchant energy business by analyzing the changes in gross margin between periods. In managing our portfolio, we may terminate, restructure, or acquire contracts. Such transactions are within the normal course of managing our portfolio and may materially impact the timing of our recognition of revenues, fuel and purchased energy expenses, and cash flows.

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

Mid-Atlantic Region our fossil, nuclear, and hydroelectric generating facilities and load-serving activities in the PJM Interconnection (PJM) region. This also includes active portfolio management of the generating assets and other physical and financial contractual arrangements, as well as other PJM competitive supply activities. In addition, due to the expiration of its power purchase agreement, beginning in June 2006 until its sale in December 2006, the results of our University Park generating facility were included in the Mid-Atlantic Region. University Park was previously included in Plants with Power Purchase Agreements.

Plants with Power Purchase Agreements our generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements. As discussed in *Note 2*, the sale of the High Desert facility resulted in a reclassification of its results of operations to discontinued operations.

Wholesale Competitive Supply our marketing, risk management, and trading operation that provides energy products and services primarily to distribution utilities, power generators, and other wholesale customers. We also provide global energy and related services and upstream and downstream natural gas services.

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

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

In December 2006, we completed the sale of these gas-fired plants:

Facility	Capacity (MW)	Unit Type	Location
High Desert	830	Combined Cycle	California
Rio Nogales	800	Combined Cycle	Texas
Holland	665	Combined Cycle	Illinois
University Park	300	Peaking	Illinois
Big Sandy	300	Peaking	West Virginia
Wolf Hills	250	Peaking	Virginia

We discuss the sale of these gas-fired generating facilities in *Note 2.*

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

	2007		2006		2005	
			(Dollar amounts in millions)			
Revenues:						
Mid-Atlantic Region	**$ 3,462.2**		$ 2,813.5		$ 2,283.9	
Plants with Power Purchase Agreements	**657.3**		650.5		665.9	
Competitive Supply						
Retail	**9,086.3**		8,014.7		6,942.3	
Wholesale	**5,469.4**		5,612.7		4,672.3	
Other	**69.3**		74.8		58.0	
Total	**$ 18,744.5**		$ 17,166.2		$ 14,622.4	
Fuel and purchased energy expenses:						
Mid-Atlantic Region	**$ (2,214.4)**		$ (1,727.6)		$ (1,436.5)	
Plants with Power Purchase Agreements	**(78.5)**		(67.9)		(72.5)	
Competitive Supply						
Retail	**(8,590.8)**		(7,570.2)		(6,668.2)	
Wholesale	**(4,618.1)**		(4,890.6)		(4,124.6)	
Other						
Total	**$ (15,501.8)**		$ (14,256.3)		$ (12,301.8)	
Gross margin:		**% of Total**		**% of Total**		**% of Total**
Mid-Atlantic Region	**$ 1,247.8**	**39%**	$ 1,085.9	37%	$ 847.4	36%
Plants with Power Purchase Agreements	**578.8**	**18**	582.6	20	593.4	25
Competitive Supply						
Retail	**495.5**	**15**	444.5	15	274.1	12
Wholesale	**851.3**	**26**	722.1	25	547.7	24
Other	**69.3**	**2**	74.8	3	58.0	3
Total	**$ 3,242.7**	**100%**	$ 2,909.9	100%	$ 2,320.6	100%

Merchant energy gross margin for 2007 includes certain effects of market price changes on derivatives designated as cash-flow and fair value hedges. These market price changes had two primary impacts on 2007:

We experienced a significant increase in the level of ineffectiveness associated with derivatives that qualified for hedge accounting treatment.

Additionally, we were required to discontinue the application of hedge accounting treatment for certain derivatives due to insufficient price correlation between the hedge and the risk being hedged. As a result, the full change in the fair value of these derivatives has been recorded in earnings.

The merchant energy gross margin impact for 2007 from the effect of market price changes on derivatives designated as cash-flow and fair value hedges is summarized as follows:

	2007

		2007
		(In millions)
Ineffectiveness on derivatives that qualified for hedge accounting treatment	$	(10.8)
Effect of reduced price correlation on derivatives that did not qualify for hedge accounting treatment		
Derivatives that were redesignated as hedges prospectively		(7.3)
Derivatives not eligible for designation as hedges prospectively		(70.8)
Total	$	(88.9)

We discuss below the impact of these items on the applicable categories of merchant energy gross margin for 2007 compared to 2006. We discuss our hedging activities in more detail in *Note 13*.

Mid-Atlantic Region

		2007		2006		2005
				(In millions)		
Revenues	**$**	**3,462.2**	$	2,813.5	$	2,283.9
Fuel and purchased energy expenses		**(2,214.4)**		(1,727.6)		(1,436.5)
Gross margin	**$**	**1,247.8**	$	1,085.9	$	847.4

The $161.9 million increase in gross margin in 2007 compared to 2006 is primarily due to approximately $249 million in higher margins on new and existing contracts. The increase in gross margin was partially offset by the following:

- the unfavorable impact of approximately $46 million related to losses recognized on cash-flow hedges due to ineffectiveness and certain cash-flow hedges that no longer qualify for hedge accounting, and

- the absence of competitive transition charge (CTC) revenue of $41.0 million related to the deregulation of the Maryland electricity markets, which ended June 30, 2006.

The increase of $238.5 million in gross margin in 2006 compared to 2005 is primarily due to approximately $340 million in higher gross margin mostly from favorable portfolio management, including higher margins on existing contracts and new contracts that began in 2006.

Our wholesale marketing, risk management, and trading operation was awarded contracts in 2006 to supply a substantial portion of BGE's standard offer service obligation to residential customers beginning July 1, 2006 through May 31, 2007. The increase in gross margin included higher revenues from BGE of approximately $256 million mostly from these new contracts during 2006 compared to 2005. This increase in gross margin was partially offset by the negative impact of higher expenses from serving the original BGE standard offer service obligation during the first six months of 2006 as variable costs, including emissions and coal, continued to increase. We discuss the expiration of the BGE residential rate freeze in more detail in the *Item 1. Business Baltimore Gas and Electric Company Electric Competition* section. Our wholesale marketing, risk management, and trading operation served fixed-price standard offer service obligations to BGE residential customers during the period from July 1, 2000 until July 1, 2006.

These increases in gross margin were partially offset by:

- lower CTC revenues of approximately $64 million due to customers that completed their obligation and the continued decline in the CTC rate, and
- lower generation at Calvert Cliffs, which resulted in lower gross margin of approximately $37 million, mostly because of a longer planned 2006 refueling outage that included replacement of the reactor vessel head.

Plants with Power Purchase Agreements

	2007	2006	2005
		(In millions)	
Revenues	**$ 657.3**	$ 650.5	$ 665.9
Fuel and purchased energy expenses	**(78.5)**	(67.9)	(72.5)
Gross margin	**$ 578.8**	$ 582.6	$ 593.4

Gross margin from our Plants with Power Purchase Agreements was about the same in 2007 compared to 2006.

Gross margin from our Plants with Power Purchase Agreements decreased slightly in 2006 compared to the same periods of 2005. This was mostly due to approximately $14 million in lower gross margin from the University Park facility, which effective June 2006 until its sale in December 2006 was included in the Mid-Atlantic Region after the expiration of its power purchase agreement in May 2006.

Competitive Supply

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

Retail

	2007	2006	2005
		(In millions)	
Accrual revenues	**$ 9,080.5**	$ 8,000.6	$ 6,944.2
Fuel and purchased energy expenses	**(8,590.8)**	(7,577.0)	(6,688.4)
Retail accrual activities	**489.7**	423.6	255.8
Mark-to-market activities	**5.8**	20.9	18.3
Gross margin	**$ 495.5**	$ 444.5	$ 274.1

The $66.1 million increase in accrual gross margin from our retail competitive supply activities during 2007 compared to 2006 is primarily due to approximately $104 million related to the positive impact of higher volumes served at higher contract rates per megawatt hour and lower costs to serve load in our retail electric operations. This increase in gross margin was partially offset by approximately $38 million related to losses at our retail gas operations recognized during 2007 on hedges due to ineffectiveness and on certain hedges that did not qualify for hedge accounting compared to 2006.

The increase in accrual gross margin of $167.8 million from our retail activities during 2006 compared to 2005 is primarily due to:

- approximately $158 million in higher margins primarily due to higher electric rates and lower costs related to our fixed-price load-serving obligations as a result of milder weather in 2006 compared to the prior year, and
- approximately $13 million in higher gross margin due to higher volumes, including 3.6 million more megawatt hours of electricity and 55 billion cubic feet more of natural gas served to retail customers during the year ended December 31, 2006 compared to 2005.

Wholesale

	2007	2006	2005
		(In millions)	
Accrual revenues	**$ 4,932.5**	$ 5,232.7	$ 4,281.8
Fuel and purchased energy expenses	**(4,618.1)**	(4,890.6)	(4,124.6)
Wholesale accrual activities	**314.4**	342.1	157.2
Mark-to-market activities	**536.9**	380.0	390.5
Gross margin	**$ 851.3**	$ 722.1	$ 547.7

Our wholesale marketing, risk management, and trading operation had $27.7 million of lower accrual gross margin during 2007 compared to 2006, primarily due to:

- the absence of approximately $67 million of gross margin associated with the gas plants that were sold in December 2006,
- lower gross margin related to the unfavorable impact of approximately $55 million of losses recognized on hedges due to ineffectiveness and on certain cash-flow hedges that did not qualify for hedge accounting,
- lower gross margin related to contract terminations and sales of approximately $39 million during 2007 compared to 2006, and

approximately $34 million in losses in 2007 reclassified from "Accumulated other comprehensive loss" to earnings related to:

the April 2007 CEP equity issuance and subsequent deconsolidation, as discussed in more detail in *Note 2* and *Note 13*. As a result of those transactions, we determined that certain hedged forecasted sales were probable of not occurring, which resulted in the reclassification of losses of approximately $22 million from "Accumulated other comprehensive loss" into earnings, and

certain amended nonderivative contracts which are now derivatives accounted for as mark-to-market. This resulted in the recognition of approximately $12 million in losses from related cash-flow hedges previously deferred in "Accumulated other comprehensive loss." We discuss these contracts in more detail in the *Mark-to-Market* section on the next page.

These decreases were partially offset by approximately $167 million of gross margin from new contracts executed, including the portfolio of contracts acquired in the southeast region during 2007, and higher gross margin associated with existing contracts.

Our wholesale marketing, risk management, and trading operation had $184.9 million of higher gross margin from accrual activities during 2006 compared to 2005 due to:

an increase of approximately $145 million, primarily due to new contracts entered into during 2006 and higher realized gross margin on existing contracts, and

an increase of approximately $85 million, primarily related to the growth in our coal and natural gas activities.

These increases in gross margin were partially offset by the following:

a decrease of $24.8 million as a result of the initial public offering of CEP and the sale of our gas-fired plants. As a result of these transactions, certain forecasted transactions associated with cash-flow hedges were determined to be probable of not occurring, and the associated amounts previously recorded in "Accumulated other comprehensive loss" were reclassified into earnings, and

a decrease of approximately $20 million from contract restructurings related to unit contingent power purchase agreements during the year ended December 2006 compared to 2005. The termination and sale of these contracts has allowed us to eliminate our exposure to performance risk under these contracts.

Mark-to-Market

Mark-to-market results include net gains and losses from origination, trading, and risk management activities for which we use the mark-to-market method of accounting. We discuss these activities and the mark-to-market method of accounting in more detail in the *Critical Accounting Policies* section and in *Note 1*.

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

	2007	**2006**	**2005**

	2007	2006	2005
		(In millions)	
Unrealized mark-to-market results			
Origination gains	**$ 41.9**	$ 13.5	$ 61.6
Risk management and trading mark-to-market			
Unrealized changes in fair value	**500.8**	387.4	347.2
Changes in valuation techniques			
Reclassification of settled contracts to realized	**(369.3)**	(372.1)	(257.7)
Total risk management and trading mark-to-market	**131.5**	15.3	89.5
Total unrealized mark-to-market*	**173.4**	28.8	151.1
Realized mark-to-market	**369.3**	372.1	257.7
Total mark-to-market results	**$ 542.7**	$ 400.9	$ 408.8

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

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

1 transaction in 2007, which is discussed in more detail below,

3 transactions completed in 2006, of which no transaction contributed in excess of $10 million pre-tax, and

6 transactions completed in 2005, one of which contributed approximately $35 million pre-tax.

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

During 2007, our wholesale marketing, risk management, and trading operation amended certain nonderivative power sales contracts such that the new contracts became derivatives subject to mark-to-market accounting under SFAS No. 133. Simultaneous with the amending of the nonderivative contracts, we executed at current market prices several new offsetting derivative power purchase contracts subject to mark-to-market accounting. The combination of these transactions resulted in substantially all of the origination gains presented for 2007 in the table on the preceding page, as well as mitigated our risk exposure under the amended contracts.

The origination gain from these transactions was partially offset by approximately $12 million of losses in our accrual portfolio due to the reclassification of losses related to cash-flow hedges previously established for the amended nonderivative contracts from "Accumulated other comprehensive loss" into earnings as discussed in our *Competitive Supply-Wholesale Accrual* section on the previous page. In the absence of these transactions, the economic value represented by the origination gain and the losses associated with cash-flow hedges would have been recognized over the remaining term of the contracts, which extended through the first quarter of 2009.

Risk management and trading mark-to-market represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the recognition of gains associated with decreases in the close-out adjustment when we are able to obtain sufficient market price information. In addition, we use derivative contracts subject to mark-to-market accounting to manage our exposure to changes in market prices primarily as a result of our gas transportation and storage activities, while in general the underlying physical transactions related to our gas activities are accounted for on an accrual basis. We discuss the changes in mark-to-market results below. We show the relationship between our mark-to-market results and the change in our net mark-to-market energy asset on the next page.

Total mark-to-market results increased $141.8 million during 2007 compared to 2006 mostly because of an increase in unrealized changes in fair value of approximately $113 million and an increase in origination gains previously discussed. The increase in unrealized changes in fair value was primarily due to:

- a more favorable price environment resulting in higher gains of approximately $132 million, and
- an increase of approximately $43 million from a favorable impact related to changes in the close-out adjustment.

These increases were partially offset by approximately $62 million from lower mark-to-market results related to the impact of certain economic hedges, primarily related to gas transportation and storage contracts that do not qualify for or are not designated as cash-flow hedges. These mark-to-market results will be offset in future periods as we realize the related accrual load-serving positions in cash.

The close-out adjustments are determined by the change in open positions, new transactions where we did not have observable market price information, and existing transactions where we have now observed sufficient market price information and/or we realized cash flows since the transactions' inception. We discuss the close-out adjustment in more detail in the *Critical Accounting Policies* section.

Total mark-to-market results decreased $7.9 million in 2006 compared to 2005 because of a decrease in origination gains of $48.1 million, mostly offset by an increase in unrealized changes in fair value of $40.2 million. Unrealized changes in fair value increased, primarily due to higher pre-tax gains of approximately $105 million related to the positive impact of certain economic hedges primarily related to gas transportation and storage contracts.

This increase in unrealized changes in fair value was partially offset by:

- a lower level of gains from risk management and trading mark-to-market activities of approximately $45 million, and
- the absence of a $19.5 million favorable impact related to changes in the close-out adjustment in 2006 compared to 2005.

Derivative Assets and Liabilities

As discussed in our *Critical Accounting Policies* section, our "Derivative assets and liabilities" include contracts accounted for as hedges and those accounted for on a mark-to-market basis.

Derivative assets and liabilities consisted of the following:

At December 31,	**2007**	**2006**
	(In millions)	

At December 31,		2007		2006
Current Assets	**$**	**961.2**	$	1,556.5
Noncurrent Assets		**1,030.2**		949.1
Total Assets		**1,991.4**		2,505.6
Current Liabilities		**1,137.1**		2,411.7
Noncurrent Liabilities		**1,118.9**		1,099.7
Total Liabilities		**2,256.0**		3,511.4
Net Derivative Position	**$**	**(264.6)**	$	(1,005.8)
Portion of net derivative position accounted for as hedges	**$**	**(937.6)**	$	(1,459.9)
Portion of net derivative position accounted for as mark-to-market	**$**	**673.0**	$	454.1

The decrease in our net derivative liability subject to hedge accounting since December 31, 2006 of $522.3 million was due primarily to an approximate $355 million change in our cash-flow hedge positions, which include both increases in power prices that increased the fair value of our cash-flow hedge positions and settlements of cash-flow hedges during 2007, and approximately $167 million of net cash-flow hedge assets acquired as part of a contract and portfolio acquisition in June 2007. We discuss this contract and portfolio acquisition in more detail in *Financial Condition Contract and Portfolio Acquisitions*.

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. The following are the primary sources of the change in our net derivative asset subject to mark-to-market accounting during 2007 and 2006:

	2007		2006	
		(In millions)		
Fair value beginning of year		**$ 454.1**		$ 167.5
Changes in fair value recorded in earnings				
Origination gains	**$ 41.9**		$ 13.5	
Unrealized changes in fair value	**500.8**		387.4	
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(369.3)**		(372.1)	
Total changes in fair value recorded in earnings		**173.4**		28.8
Changes in value of exchange-listed futures and options		**18.6**		277.8
Net change in premiums on options		**(19.0)**		(29.8)
Contracts acquired		**83.8**		
Other changes in fair value		**(37.9)**		9.8
Fair value at end of year		**$ 673.0**		$ 454.1

Changes in our net derivative asset subject to mark-to-market accounting that affected earnings were as follows:

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

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

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

Our net derivative asset subject to mark-to-market accounting also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income:

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 "Derivative 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 derivative asset and premiums on options sold as a decrease in the net derivative asset.

Contracts acquired represents the initial fair value of acquired derivative contracts recorded in "Derivative assets and liabilities" in our Consolidated Balance Sheets.

Other changes in fair value include transfers of derivative assets and liabilities between accounting methods resulting from the designation and de-designation of cash-flow hedges.

The settlement terms of our net derivative asset subject to mark-to-market accounting and sources of fair value as of December 31, 2007 are as follows:

	Settlement Term							
	2008	2009	2010	2011	2012	2013	Thereafter	Fair Value
	(In millions)							
Prices provided by external sources (1)	$ 359.0	$ 50.6	$ 26.2	$ 30.3	$ 28.0	$ 6.8	$ 3.0	$ 503.9
Prices based on models	(1.8)	71.1	74.4	36.5	(11.4)	(1.3)	1.6	169.1
Total net mark-to-market energy asset	$ 357.2	$ 121.7	$ 100.6	$ 66.8	$ 16.6	$ 5.5	$ 4.6	$ 673.0

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

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

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

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

- forward purchases and sales of electricity during peak and off-peak hours for delivery terms primarily through 2011, but up to 2012, depending upon the region,
- options for the purchase and sale of electricity during peak hours for delivery terms through 2009, depending upon the region,
- forward purchases and sales of electric capacity for delivery terms primarily through 2009, but up to 2011, depending on the region,
- forward purchases and sales of natural gas through 2012, coal through 2010, and oil for delivery terms through 2011, and
- options for the purchase and sale of natural gas for delivery terms through 2009.

The remainder of our net derivative asset subject to mark-to-market accounting 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, risk management, and trading 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 preceding 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 realize an amount different from the value reflected in the table. However, based upon the nature of the wholesale marketing, risk management, and trading operation, we generally 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. In general, 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, 2007 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 our net derivative assets and liabilities subject to mark-to-market accounting, and it is possible that such variations could be material.

In 2006, the Financial Accounting Standards Board issued SFAS No. 157 that will impact our accounting for derivative instruments. We discuss this in more detail in *Note 1*.

Other

	2007	2006	2005
		(In millions)	
Revenues	**$ 69.3**	$ 74.8	$ 58.0

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 based on the facilities' energy source or the use of a cogeneration process. In addition, during 2007, our merchant energy business obtained and currently holds a 50% interest in a joint venture to develop, own, and operate new nuclear projects in the United States and Canada (UniStar Nuclear Energy, LLC (UNE)). Earnings from these investments were $2.8 million in 2007, $13.8 million in 2006, and $3.6 million in 2005.

Investments

Our investment in qualifying facilities and domestic power projects, CEP, and joint ventures consisted of the following:

Book Value at December 31,	2007	2006
	(In millions)	
Project Type		
Coal	**$ 119.6**	$ 125.7
Hydroelectric	**54.7**	55.1
Geothermal	**37.6**	40.5
Biomass	**43.6**	46.6
Fuel Processing	**26.8**	33.7
Solar	**7.0**	7.0
CEP	**143.0**	
Joint ventures:		
Shipping JV	**56.6**	
UNE	**52.2**	
Other	**1.1**	
Total	**$ 542.2**	$ 308.6

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, fuel processing projects, as well as our equity investments in our joint ventures and CEP 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* and *Item 1A. Risk Factors* sections. 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.

Current California statutes and regulations require load-serving entities to increase their procurement of renewable energy resources and mandate statewide reductions in greenhouse gas emissions. Given the need for electric power and the statutory and regulatory requirements increasing demand for renewable resource technologies, we believe California will continue to foster an environment that supports the use of renewable energy and continues certain subsidies that will make renewable energy projects economical. However, should California legislation and regulatory policies and federal energy policies fail to adequately support 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.

Operating Expenses

Our merchant energy business operating expenses increased $242.4 million during 2007 compared to 2006 mostly due to an increase at our competitive supply operations totaling $218.4 million, primarily related to the continued growth of this operation and higher compensation and benefit costs.

Our merchant energy business operating expenses increased $203.3 million in 2006 compared to 2005 mostly due to the following:

- an increase of $139.2 million at our competitive supply operations, primarily related to higher labor and benefit costs and the impact of inflation on other costs,
- an increase of $22.7 million at our upstream gas operations, primarily due to acquisitions made in June 2005, and
- an increase of approximately $18 million at our generating facilities, which includes higher expenses associated with longer planned outages, offset in part by lower expenses that resulted from our productivity initiatives.

Impairment Losses and Other Costs

Our impairment losses and other costs are discussed in more detail in *Note 2*.

Workforce Reduction Costs

Our merchant energy business recognized expenses associated with our workforce reduction efforts as discussed in more detail in *Note 2*.

Merger-Related Costs

We discuss costs related to the proposed merger with FPL Group, which has been terminated, in *Note 15*.

Depreciation, Depletion and Amortization Expense

Merchant energy depreciation, depletion, and amortization expenses increased $11.2 million in 2007 compared to 2006 mostly due to:

$30.9 million related to our upstream natural gas operations, primarily due to acquisitions made in 2007, and

$6.2 million primarily related to additions to our nuclear facilities, including the impact of the uprate at our Ginna facility in 2006.

These increases were partially offset by $29.0 million primarily related to the absence of depreciation associated with the gas plants that were sold in December 2006.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $9.8 million in 2007 compared to 2006, primarily due to $5.8 million lower gross receipts tax at our retail competitive supply operation and a $4.2 million decrease due to the sale of our gas-fired plants.

Merchant energy taxes other than income taxes increased $13.3 million in 2006 compared to 2005 mostly due to $5.3 million related to higher gross receipts taxes at our retail competitive supply operation and $3.1 million related to our working interests in gas producing properties.

Regulated Electric Business

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

Results

	2007	2006	2005
		(In millions)	
Revenues	**$ 2,455.7**	$ 2,115.9	$ 2,036.5
Electricity purchased for resale expenses	**(1,500.4)**	(1,167.8)	(1,068.9)
Operations and maintenance expenses	**(376.1)**	(351.3)	(318.4)
Merger-related costs		(3.3)	(4.0)
Depreciation and amortization	**(187.4)**	(181.5)	(185.8)
Taxes other than income taxes	**(140.2)**	(134.9)	(135.3)
Income from Operations	**$ 251.6**	$ 277.1	$ 324.1
Net Income	**$ 97.9**	$ 120.2	$ 149.4
Other Items Included in Operations (after-tax)			
Merger-related costs	**$**	$ (0.8)	$ (3.7)

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 the regulated electric business decreased $22.3 million in 2007 compared to 2006, primarily due to the following:

- increased operations and maintenance expenses of $15.0 million after-tax mostly due to higher labor and benefits costs,
- increased depreciation and amortization of $3.6 million after-tax, and
- increased taxes other than income taxes of $3.2 million after-tax.

The decrease was partially offset by an increase in revenues less electricity purchased for resale expenses of $4.4 million after-tax, which includes the impact of Senate Bill 1 credits.

Net income from the regulated electric business decreased $29.2 million in 2006 compared to 2005 mostly because of the following:

- increased operations and maintenance expenses of $19.9 million after-tax mostly due to higher labor and benefit costs and incremental costs associated with 2006 storms, and
- decreased revenues less electricity purchased for resale expenses of $11.8 million after-tax.

Electric Revenues

The changes in electric revenues in 2007 and 2006 compared to the respective prior year were caused by:

	2007	2006
	(In millions)	
Distribution volumes	**$ 19.5**	$ (40.9)
Standard offer service	**267.8**	433.7
Rate stabilization credits	**34.6**	(321.9)
Rate stabilization recovery	**36.1**	
Financing credits	**(7.5)**	
Senate Bill 1 credits	**(29.7)**	
Total change in electric revenues from electric system sales	**320.8**	70.9
Other	**19.0**	8.5
Total change in electric revenues	**$ 339.8**	$ 79.4

<u>*Distribution Volumes*</u>

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

The percentage changes in our electric system distribution volumes, by type of customer, in 2007 and 2006 compared to the respective prior year were:

	2007	2006
Residential	**3.7%**	(6.4)%
Commercial	**3.6**	(0.6)
Industrial	**0.2**	(7.5)

In 2007, we distributed more electricity to residential customers due to colder winter weather and an increased number of customers, partially offset by decreased usage per customer. We distributed more electricity to commercial customers due to increased usage per customer, colder winter weather, and an increased number of customers. We distributed essentially the same amount of electricity to industrial customers.

In 2006, we distributed less electricity to residential customers mostly due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed less electricity to commercial customers mostly due to milder weather, partially offset by an increased number of customers and increased usage per customer. We distributed less electricity to industrial customers mostly due to decreased usage per customer.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier. We discuss the provisions of Maryland's Senate Bill 1 related to residential electric rates in the *Business Environment Regulation Maryland Senate Bills 1 and 400* section.

Standard offer service revenues increased in 2007 compared to 2006, primarily due to an increase in the standard offer service rates following the expiration of residential rate freeze service in July 2006, partially offset by lower standard offer service volumes.

Standard offer service revenues were higher in 2006 compared to 2005, mostly due to an increase to market prices in the standard offer service rates due to the expiration of the residential rate freeze in July 2006, partially offset by lower standard offer service volumes.

Rate Stabilization Credits

As a result of Senate Bill 1, we were required to defer from July 1, 2006 until May 31, 2007 a portion of the full market rate increase resulting from the expiration of the residential rate freeze. In addition, we offered a plan also required under Senate Bill 1 allowing residential customers the option to defer the transition to market rates from June 1, 2007 until January 1, 2008. The total amount deferred under this additional plan was $6.5 million as of December 31, 2007.

In 2007 compared to 2006, the amount of rate stabilization credits provided to residential electric customers decreased, primarily due to the end of the first deferral period on May 31, 2007, partially offset by the additional deferrals during the second deferral period, which ended on December 31, 2007.

Rate Stabilization Recovery

BGE began recovering amounts deferred during the first rate deferral period that ended on May 31, 2007 in late June 2007.

Financing Credits

Concurrent with the recovery of the deferred amounts related to the first rate deferral period, we are providing credits to residential customers to compensate them primarily for income tax benefits associated with the financing of the deferred amounts with rate stabilization bonds. We discuss the rate stabilization bonds in more detail in *Note 9*.

Senate Bill 1 Credits

As a result of Senate Bill 1, beginning January 1, 2007, we were required to provide to residential electric customers a credit equal to the amount collected from all BGE ratepayers for the decommissioning of our Calvert Cliffs nuclear power plant and to suspend collection of the residential return component of the Provider of Last Resort (POLR) administrative charge collected through residential POLR rates through May 31, 2007. Under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, we were required to reinstate collection of the residential return component of the POLR administration charge in POLR rates and to provide all residential electric customers a credit for the residential return component of the administrative charge.

Electricity Purchased for Resale Expenses

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

	2007	2006	2005
		(In millions)	
Actual costs	**$ 1,759.2**	$ 1,489.7	$ 1,068.9
Deferral under rate stabilization plan	**(287.3)**	(321.9)	
Recovery under rate stabilization plans	**28.5**		
Electricity purchased for resale expenses	**$ 1,500.4**	$ 1,167.8	$ 1,068.9

Actual Costs

BGE's actual costs for electricity purchased for resale increased $269.5 million for 2007 compared to 2006, primarily due to higher contract prices to purchase electricity for our residential customers following the expiration of contracts that were executed in 2000 as part of the implementation of electric deregulation in Maryland, partially offset by lower volumes.

BGE's actual costs for electricity purchased for resale increased $420.8 million in 2006 compared to 2005 due to higher contract prices to purchase electricity resulting from the expiration of contracts that were executed in 2000 as part of the implementation of electric deregulation in Maryland, partially offset by lower standard offer service volumes.

Deferral under Rate Stabilization Plan

We defer the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under Senate Bill 1. In 2007, we deferred $287.3 million in electricity purchased for resale expenses. Since July 1, 2006, we have deferred $609.2 million in electricity purchased for resale expenses. In 2006, we deferred $321.9 million in electricity purchased for resale expenses. These deferred expenses, plus carrying charges, are included in "Regulatory Assets (net)" in our, and BGE's, Consolidated Balance Sheets. We discuss the provisions of Senate Bill 1 related to residential electric rates in the *Business Environment Regulation Maryland Senate Bills 1 and 400* section.

Recovery under Rate Stabilization Plans

In late June 2007, we began recovering previously deferred amounts from customers. We recovered $28.5 million in 2007 in deferred electricity purchased for resale expenses. As discussed later, these collections secure the payment of principal and interest and other ongoing costs associated with rate stabilization bonds issued by a subsidiary of BGE in June 2007.

Electric Operations and Maintenance Expenses

Regulated operations and maintenance expenses increased $24.8 million in 2007 compared to 2006 mostly due to higher labor and benefit costs and the impact of inflation on other costs of $16.9 million, customer education in relation to rate stabilization of $5.3 million and increased uncollectible accounts receivable expense of $2.9 million.

Regulated electric operations and maintenance expenses increased $32.9 million in 2006 compared to 2005 mostly due to higher labor and benefit costs and the impact of inflation on other costs and $13.1 million of incremental distribution service restoration expenses associated with 2006 storms.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense increased $5.9 million in 2007 compared to 2006, primarily due to additional property placed in service.

Regulated electric depreciation and amortization expense decreased $4.3 million in 2006 compared to 2005 mostly because of the absence of $6.9 million amortization expense associated with certain software, partially offset by $3.0 million related to additional property placed in service.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $5.3 million in 2007 in comparison with 2006, primarily due to increased property taxes.

Regulated Gas Business

Our regulated gas business is discussed in detail in *Item 1. Business Gas Business* section.

Results

	2007	2006	2005
		(In millions)	
Revenues	**$ 962.8**	$ 899.5	$ 972.8
Gas purchased for resale expenses	**(639.8)**	(581.5)	(687.5)
Operations and maintenance expenses	**(157.5)**	(144.8)	(131.8)
Merger-related costs		(1.4)	(1.4)
Depreciation and amortization	**(46.8)**	(46.0)	(46.6)
Taxes other than income taxes	**(36.1)**	(33.8)	(33.1)
Income from Operations	**$ 82.6**	$ 92.0	$ 72.4
Net Income	**$ 28.8**	$ 37.0	$ 26.7
Other Items Included in Operations (after-tax)			
Merger-related costs	**$**	$ (0.4)	$ (1.3)

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.

Net income from the regulated gas business decreased $8.2 million in 2007 compared to 2006, primarily due to increased operations and maintenance expenses of $7.7 million after-tax.

Net income from the regulated gas business increased $10.3 million in 2006 compared to 2005 mostly due to increased revenues less gas purchased for resale expenses of $19.8 million after-tax, which was primarily due to the increase in gas base rates that was approved by the Maryland PSC in December 2005. This increase was partially offset by higher operations and maintenance expenses of $7.9 million after-tax.

Gas Revenues

The changes in gas revenues in 2007 and 2006 compared to the respective prior year were caused by:

	2007	2006
	(In millions)	
Distribution volumes	**$ 19.3**	$ (38.0)
Base rates	**0.2**	33.4
Gas revenue decoupling	**(20.1)**	28.4
Gas cost adjustments	**74.4**	(112.3)
Total change in gas revenues from gas system sales	**73.8**	(88.5)
Off-system sales	**(11.2)**	13.9
Other	**0.7**	1.3
Total change in gas revenues	**$ 63.3**	$ (73.3)

<u>Distribution Volumes</u>

The percentage changes in our distribution volumes, by type of customer, in 2007 and 2006 compared to the respective prior year were:

	2007	**2006**
Residential	**17.7%**	(17.0)%
Commercial	**14.6**	(13.3)
Industrial	**(11.3)**	3.2

In 2007, we distributed more gas to residential customers due to colder weather, increased usage per customer and an increased number of customers. We distributed more gas to commercial customers due to an increased number of customers and colder weather, partially offset by decreased usage per customer. We distributed less gas to industrial customers mostly due to decreased usage per customer.

In 2006, we distributed less gas to residential and commercial customers compared to 2005 mostly due to milder weather and decreased usage per customer, partially offset by an increased number of customers. We distributed more gas to industrial customers mostly due to increased usage per customer.

Base Rates

In December 2005, the Maryland PSC issued an order granting BGE a $35.6 million annual increase in its gas base rates. In December 2006, the Baltimore City Circuit Court upheld the rate order. However, certain parties have filed an appeal with the Court of Special Appeals. We cannot provide assurance that the Maryland PSC's order will not be reversed in whole or in part or that certain issues will not be remanded to the Maryland PSC for reconsideration.

Gas Revenue Decoupling

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather and usage patterns per customer on our gas distribution volumes. This means our monthly gas distribution revenues are based on weather and usage that is considered "normal" for the month and, therefore, are affected by customer growth and not by actual weather or usage 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 in 2007 compared to 2006 because we sold more gas at higher prices.

Gas cost adjustment revenues decreased in 2006 compared to 2005 because we sold less gas at lower prices.

Off-System Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Off-system gas sales, which occur after BGE has 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 in 2007 compared to 2006 because we sold gas at lower prices, partially offset by more gas sold.

Revenues from off-system gas sales increased in 2006 compared to 2005 because we sold more gas, partially offset by lower prices.

Gas Purchased For Resale Expenses

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

Gas purchased for resale expenses increased $58.3 million in 2007 compared to 2006 because we purchased more gas, partially offset by lower prices.

Gas purchased for resale expenses decreased $106.0 million in 2006 compared to 2005 because we purchased less gas at lower prices.

Gas Operations and Maintenance Expenses

Regulated gas operations and maintenance expenses increased $12.7 million in 2007 compared to 2006 mostly due to higher labor and benefit costs and the impact of inflation on other costs of $8.9 million and increased uncollectible accounts receivable expense of $1.2 million.

Regulated gas operations and maintenance expenses increased $13.0 million in 2006 compared to 2005 mostly due to higher labor and benefit costs and the impact of inflation on other costs.

Gas Taxes Other Than Income Taxes

Gas taxes other than income taxes increased $2.3 million in 2007 compared to 2006, primarily due to increased property taxes.

Other Nonregulated Businesses

Results

	2007	2006	2005
		(In millions)	

	2007		2006		2005	
Revenues	**$**	**249.8**	$	231.0	$	207.0
Operating expenses		**(173.5)**		(173.1)		(156.2)
Merger-related costs				(0.5)		(0.4)
Depreciation and amortization		**(53.7)**		(37.7)		(40.2)
Taxes other than income taxes		**(2.4)**		(2.0)		(2.0)
Income from Operations	**$**	**20.2**	$	17.7	$	8.2
Income from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	**$**	**16.5**	$	11.3	$	0.4
Income from discontinued operations (after-tax)				0.9		20.6
Cumulative effects of changes in accounting principles (after-tax)						0.2
Net Income	**$**	**16.5**	$	12.2	$	21.2
Other Items Included In Operations (after-tax)						
Merger-related costs	**$**		$	(0.2)	$	(0.2)

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 increased $4.3 million in 2007 compared to 2006, primarily due to higher construction volume at our energy projects business.

Net income from our other nonregulated businesses decreased $9.0 million in 2006 compared to 2005, primarily due to a $19.7 million decrease in income from discontinued operations, partially offset by a $10.7 million increase in net income from our remaining other nonregulated businesses, including an increase in net income from our continued liquidation of our real estate investments.

Consolidated Nonoperating Income and Expenses

Gains on Sale of CEP Equity

In November 2006, CEP, a limited liability company formed by Constellation Energy, completed an initial public offering of 5.2 million common units at $21 per unit. As a result of the initial public offering of CEP, we recognized a pre-tax gain of $28.7 million, or $17.9 million after recording deferred taxes on the gain. As a result of subsequent sales of equity by CEP, which reduced our relative ownership percentage, we recognized pre-tax gains totaling $63.3 million in 2007. We discuss the issuances of CEP equity in more detail in *Note 2*.

Other Income

Other income increased in 2007 compared to 2006, mostly due to higher interest and investment income due to a higher cash balance.

Total other income at BGE increased in 2007 compared to 2006, primarily due to carrying charges related to rate stabilization deferrals of "Electricity Purchased for Resale" expense. We discuss the rate stabilization deferrals in more detail in the *Regulated Electric Business* section.

Fixed Charges

Fixed charges decreased in 2007 compared to 2006, mostly due to a lower average level of debt outstanding.

Fixed charges at BGE increased in 2007 compared to 2006 mostly due to interest expense recognized on debt that was issued in October 2006 and the rate stabilization bonds issued in June 2007.

Fixed charges increased $18.5 million in 2006 compared to 2005 mostly because of a higher level of debt outstanding, including commercial paper borrowings, and higher interest rates in 2006 compared to 2005.

Total fixed charges for BGE increased $9.1 million in 2006 compared to 2005 mostly because of a higher level of debt outstanding.

Income Taxes

The differences in income taxes resulted 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 in *Note 10*.

Our income taxes increased $77.3 million in 2007 compared to 2006 mostly because of an increase in pre-tax income and a decrease in synthetic fuel tax credits of $20 million.

In 2007, the State of Maryland increased its corporate income tax rate from 7% to 8.25%, effective January 1, 2008. The impact of adjusting all existing deferred income tax assets and liabilities for this change in the period of enactment was not material to us. However, this did impact BGE, as discussed below.

Income taxes at BGE decreased $6.2 million in 2007 compared to 2006, primarily due to lower pre-tax income partially offset by the increase in the Maryland state tax rate.

Income taxes increased $187.1 million in 2006 compared to 2005, primarily due to a higher level of pre-tax income, including the gain on sale of gas-fired plants and the gain on the initial public offering of CEP, as well as a decrease in synthetic fuel tax credits.

Total income taxes for BGE decreased $17.7 million in 2006 compared to 2005 mostly due to lower pre-tax income.

Financial Condition

Cash Flows

The following table summarizes our 2007 cash flows by business segment, as well as our consolidated cash flows for 2007, 2006, and 2005.

	2007 Segment Cash Flows			Consolidated Cash Flows		
	Merchant	Regulated	Other	2007	2006	2005
			(In millions)			
Operating Activities						
Net income	$ 678.3	$ 126.7	$ 16.5	$ 821.5	$ 936.4	$ 623.1
Non-cash adjustments to net income	428.2	93.4	13.0	534.6	195.4	746.0
Changes in working capital	(260.9)	(120.9)	8.6	(373.2)	(677.7)	(747.6)
Defined benefit obligations*				(53.6)	40.5	3.4
Other	(18.4)	(45.8)	62.7	(1.5)	30.7	2.3
Net cash provided by operating activities	827.2	53.4	100.8	927.8	525.3	627.2
Investing Activities						
Investments in property, plant and equipment	(837.0)	(375.8)	(82.9)	(1,295.7)	(962.9)	(760.0)
Asset acquisitions and business combinations, net of cash acquired	(347.5)			(347.5)	(137.6)	(237.2)
Investment in nuclear decommissioning trust fund securities	(659.5)			(659.5)	(492.5)	(370.8)
Proceeds from nuclear decommissioning trust fund securities	650.7			650.7	483.7	353.2
Net proceeds from sale of gas-fired plants and discontinued operations					1,630.7	289.4
Issuances of loans receivable	(19.0)			(19.0)	(65.4)	(82.8)
Sale of investments and other assets	3.9	0.8	9.2	13.9	43.9	14.4
Contract and portfolio acquisitions	(474.2)			(474.2)	(2.3)	(336.2)
Decrease (increase) in restricted funds	(2.9)	(42.3)	(64.7)	(109.9)	7.7	(4.0)
Other investments	(44.1)		(1.2)	(45.3)	54.8	(40.0)
Net cash (used in) provided by investing activities	(1,729.6)	(417.3)	(139.6)	(2,286.5)	560.1	(1,174.0)
Cash flows from operating activities less cash flows from investing activities	$ (902.4)	$ (363.9)	$ (38.8)	(1,358.7)	1,085.4	(546.8)
Financing Activities*						
Net (repayment) issuance of debt				(33.1)	242.2	(339.6)
Proceeds from issuance of common stock				65.1	84.4	96.9
Common stock dividends paid				(306.0)	(264.0)	(228.8)
Reacquisition of common stock				(409.5)		
Proceeds from initial public offering of CEP					101.3	
Proceeds from contract and portfolio acquisitions				847.8	221.3	1,026.9
Other				1.2	5.5	98.1
Net cash provided by financing activities				165.5	390.7	653.5
Net (decrease) increase in cash and cash equivalents				$ (1,193.2)	$ 1,476.1	$ 106.7

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

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

Cash Flows from Operating Activities

Cash provided by operating activities was $927.8 million in 2007 compared to $525.3 million in 2006. This $402.5 million increase was primarily due to an increase in non-cash adjustments to net income and favorable changes in working capital, offset in part by unfavorable changes in net income.

Non-cash adjustments to net income increased $339.2 million in 2007 compared to 2006, primarily due to the absence of a $191.4 million gain on sale of gas-fired plants and discontinued operations in 2006, a change in deferred fuel costs of $100.5 million related mostly to lower deferrals of electricity purchased for resale under the BGE rate stabilization plan, and a $98.2 million increase in deferred income tax expense.

Changes in working capital had a negative impact of $373.2 million on cash flows from operations in 2007 compared to a negative impact of $677.7 million in 2006. The improvement in working capital of $304.5 million was due to a $200.8 million change in working capital primarily related to higher fuel stock purchases in 2006 as compared to 2007.

Cash provided by operating activities was $525.3 million in 2006 compared to $627.2 million in 2005. This $101.9 million decrease was primarily due to a decrease in non-cash adjustments to net income in 2006, partially offset by favorable changes in net income and working capital.

Non-cash adjustments to net income decreased by $550.6 million in 2006 compared to 2005, primarily due to the change in deferred fuel costs of $336.6 million related mostly to the deferred recovery of electricity purchased for resale under the BGE rate stabilization plan. We discuss the rate stabilization plan in more detail in the *Item 1. Business Baltimore Gas and Electric Company Electric Business Electric Competition* section and *Note 1*. In addition, our gains on the sale of gas-fired plants and discontinued operations increased $177.6 million in 2006 compared to 2005. We discuss this in more detail in *Note 2*.

Changes in working capital had a negative impact of $677.7 million on cash flow from operations in 2006 compared to a negative impact of $747.6 million in 2005. The negative impact of $677.7 million related to working capital was primarily due to the commodity price environment and increased risk management and trading activities that resulted in an increase of approximately $630 million in net cash collateral requirements, primarily for requirements on exchange-settled transactions. This increase in cash collateral requirements was accompanied by a decrease in our letters of credit requirements.

Cash Flows from Investing Activities

Cash used in investing activities was $2,286.5 million in 2007 compared to cash provided by of $560.1 million in 2006. The $2,846.6 million increase in cash used in 2007 compared to 2006 was primarily due to the following:

- the absence of the net proceeds of $1,630.7 million from the sale of gas-fired plants and discontinued operations received in 2006,
- a $471.9 million increase in contract and portfolio acquisitions that we discuss in more detail below,
- a $332.8 million increase in investments in property, plant and equipment primarily related to growth within our merchant segment, which includes spending related to environmental controls at our generating facilities, and
- a $209.9 million increase in acquisitions, primarily related to our acquisitions of working interests in gas and oil producing properties and a retail competitive supply business as discussed in more detail in *Note 15*.

Cash provided by investing activities was $560.1 million in 2006 compared to cash used in investing activities $1,174.0 million in 2005. The $1,734.1 million favorable change in 2006 compared to 2005 was primarily due to the increase in proceeds from sale of gas-fired plants and discontinued operations of $1,341.3 million and a decrease of $333.9 million in cash paid for contract and portfolio acquisitions.

Cash Flows from Financing Activities

Cash provided by financing activities was $165.5 million in 2007 compared to $390.7 million in 2006. The decrease of $225.2 million was primarily due to cash used for reacquisition of common stock of $409.5 million, a net decrease in cash related to changes in short-term borrowings and long-term debt of $275.3 million, and a net decrease of $101.3 million in proceeds from the initial public offering of CEP in 2006. This was partially offset by an increase in gross proceeds from contract and portfolio acquisitions of $626.5 million, which we discuss below.

In October 2007, our board of directors approved a common share repurchase program for up to $1 billion of our outstanding common shares. Subsequent to this approval, on October 31, 2007, we entered into an accelerated share repurchase agreement with a financial institution, and on November 2, 2007 we purchased 2,023,527 of outstanding shares of our common stock for $250 million. We discuss the share repurchase program in more detail in *Note 9*.

Cash provided by financing activities was $390.7 million in 2006 compared to $653.5 million in 2005. The decrease of $262.8 million in cash provided in 2006 compared to 2005 was primarily due to a decrease in proceeds from acquired contracts of $805.6 million, a decrease in other financing activities of $92.6 million, and a $35.2 million increase in our dividends paid in 2006 compared to 2005. We discuss the proceeds from acquired contracts below. These decreases were partially offset by a net increase in cash related to changes in short-term borrowings and long-term debt of $581.8 million and $101.3 million in proceeds from the initial public offering of CEP.

Contract and Portfolio Acquisitions

During 2007, 2006, and 2005, our merchant energy business acquired several pre-existing energy purchase and sale agreements, which generated significant cash flows at the inception of the contracts. These agreements had contract prices that differed from market prices at closing, which resulted in cash payments from the counterparty at the acquisition of the contract. We received net cash of $373.6 million in 2007, $219.0 million in 2006, and $690.7 million in 2005 for various contract and portfolio acquisitions. We reflect the underlying contracts on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether they were at above- or below-market prices at closing; therefore, we have also reflected them on a gross basis in cash flows from investing and financing activities in our Consolidated

Statements of Cash Flows as follows:

Year ended December 31,	**2007**	**2006**	**2005**
	(In millions)		
Financing activities proceeds from contract and portfolio acquisitions	**$ 847.8**	$ 221.3	$ 1,026.9
Investing activities contract and portfolio acquisitions	**(474.2)**	(2.3)	(336.2)
Cash flows from contract and portfolio acquisitions	**$ 373.6**	$ 219.0	$ 690.7

We record the proceeds we receive to acquire energy purchase and sale agreements as a financing cash inflow because it constitutes a prepayment for a portion of the market price of energy, which we will buy or sell over the term of the agreements and does not represent a cash inflow from current period operating activities. For those acquired contracts that are derivatives, we record the ongoing cash flows related to the contract with the counterparties as financing cash inflows in accordance with SFAS No. 149. For those acquired contracts that are not derivatives, we record the ongoing cash flows related to the contract as operating cash flows.

We discuss certain of these contract and portfolio acquisitions in more detail in *Note 5.*

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. Generally, 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, political, legislative and regulatory risk, and the amount of debt as a component of total capitalization.

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	F2
Senior Unsecured Debt	BBB+	Baa1	BBB+
BGE			
Commercial Paper	A-2	P-2	F2
Mortgage Bonds	A	Baa1	A
Senior Unsecured Debt	BBB+	Baa2	A-
Rate Stabilization Bonds *	AAA	Aaa	AAA
Trust Preferred Securities	BBB-	Baa3	BBB+
Preference Stock	BBB-	Ba1	BBB+

** Bonds issued by RSB BondCo LLC, a subsidiary of BGE*

In February 2008, Fitch Ratings placed both Constellation Energy and BGE on Ratings Watch Negative due to the current political and regulatory environment in Maryland. Additionally, in February 2008, Standard & Poors Rating Group affirmed the ratings of both Constellation Energy and BGE. They kept the outlook on the ratings as negative due to the current political and regulatory environment in Maryland. We discuss the potential effect of a ratings downgrade in the *Liquidity Provisions* section.

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, 2007, we had approximately $3.85 billion of credit under a five-year facility that expires in July 2012. In December 2007, we entered into an additional one-year credit facility totaling $250.0 million. This facility amended and restated a $200.0 million facility that expired in December 2007.

These revolving credit facilities allow the issuance of letters of credit up to $4.1 billion. At December 31, 2007, letters of credit that totaled $1.8 billion were issued under all of our facilities, which results in approximately $2.3 billion of unused credit facilities. Additionally, in January 2008, we entered into a new six month line of credit totaling $500.0 million. This line of credit expires in July 2008 and has an option to be extended for an additional six months, subject to the lender's approval.

We enter into these facilities to ensure adequate liquidity to support our operations. Currently, we use the facilities to issue letters of credit primarily for our merchant energy business.

We expect to fund future acquisitions with an overall goal of maintaining a strong investment grade credit profile.

BGE

BGE currently maintains a $400.0 million five-year revolving credit facility expiring in 2011. BGE can borrow directly from the banks or use the facilities to allow commercial paper to be issued. As of December 31, 2007, BGE had $0.7 million in letters of credit issued, which results in $399.3 million in unused credit facilities.

Capital Resources

Our actual consolidated capital requirements for the years 2005 through 2007, along with the estimated annual amount for 2008, 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 2008 and 2009 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* and *Item 1A. Risk Factors* sections.

	2005	2006	2007	2008
		(In millions)		
Nonregulated Capital Requirements:				
Merchant energy (excludes acquisitions)				
Generation plants	$ 182	$ 235	$ 201	$ 450
Environmental controls	1	17	157	550
Portfolio acquisitions/investments	231	227	512	565
Technology/other	165	152	160	135
Nuclear fuel	130	137	148	200
Total merchant energy capital requirements	709	768	1,178	1,900
Other nonregulated capital requirements	32	21	85	80
Total nonregulated capital requirements	741	789	1,263	1,980
Regulated Capital Requirements:				
Regulated electric	241	297	340	415
Regulated gas	50	63	62	80
Total regulated capital requirements	291	360	402	495
Total capital requirements	$ 1,032	$ 1,149	$ 1,665	$ 2,475

As of the date of this report, we have not completed our 2009 capital budgeting process, but expect our 2009 capital requirements to be approximately $2.0 billion.

Our environmental controls capital requirements are affected by new rules or regulations that require modifications to our facilities. We are in the process of installing additional air emission control equipment at certain of our coal-fired generating facilities in Maryland and plan to install additional air emission control equipment at co-owned coal-fired generating facilities in Pennsylvania. We estimate another $400 million of capital spending from 2009-2012 for environmental controls. 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 environmental regulations and legislation, and
- enhancements to our information technology infrastructure.

Regulated Electric and Gas

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

Funding for Capital Requirements

Merchant Energy Business

Funding for our merchant energy business is expected from internally generated funds. If internally generated funds are not sufficient to meet funding requirements, we 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. If internally generated funds are not sufficient to meet funding requirements, we have available sources 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. If internally generated funds are not sufficient to meet funding requirements, we have available sources from 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 assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made.

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.

We detail our contractual payment obligations as of December 31, 2007 in the following table:

	Payments				
	2008	2009-2010	2011-2012	Thereafter	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt:[1]					
Nonregulated					
Principal	$ 5.6	$ 501.9	$ 742.9	$ 1,580.4	$ 2,830.8
Interest	165.6	286.9	238.0	1,218.5	1,909.0
Total	171.2	788.8	980.9	2,798.9	4,739.8
BGE					
Principal	350.0	121.6	254.2	1,489.3	2,215.1
Interest	128.9	215.6	197.4	1,411.5	1,953.4
Total	478.9	337.2	451.6	2,900.8	4,168.5
BGE preference stock				190.0	190.0
Operating leases[2]	505.6	454.6	470.7	892.5	2,323.4
Purchase obligations:[3]					
Purchased capacity and energy[4]	425.2	489.6	213.8	276.4	1,405.0
Fuel and transportation	1,825.1	1,503.5	649.7	918.9	4,897.2
Other	259.1	41.8	20.3	19.3	340.5
Other noncurrent liabilities:					
FIN 48 tax liability	22.7	18.4		14.0	55.1
Pension benefits[5]	84.1	170.8	162.9		417.8
Postretirement and post employment benefits[6]	43.0	99.6	116.2	229.1	487.9
Total contractual payment obligations	$ 3,814.9	$ 3,904.3	$ 3,066.1	$ 8,239.9	$ 19,025.2

1 *Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $339.8 million early through remarketing features. Interest on variable rate debt is included based on the December 31, 2007 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.*

5 *Amounts related to pension benefits reflect our current 5-year forecast for contributions for our qualified pension plans and participant payments for our nonqualified pension plans. Refer to Note 7 for more detail on our pension plans.*

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 in our Consolidated Balance Sheets as discussed in Note 7.*

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, risk management, and trading operation and our competitive supply operations.

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, risk management, and trading operation, we are obligated to post collateral if Constellation Energy's senior unsecured credit ratings declined below established contractual levels. Based on contractual provisions at December 31, 2007, we estimate that if Constellation Energy's senior unsecured debt were downgraded we would have the following additional collateral obligations:

Credit Ratings Downgraded to	Level Below Current Rating	Incremental Obligations	Cumulative Incremental Obligations
		(In millions)	
BBB/Baa2	1	$ 327	$ 327
BBB-/Baa3	2	281	608
Below investment grade	3	728	1,336

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

The credit facilities of Constellation Energy and BGE have limited material adverse change clauses, none of which would prohibit draws under the existing facilities. 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, 2007, the debt to capitalization ratios as defined in the credit agreements were no greater than 46%. The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2007, the debt to capitalization ratio for BGE as defined in this credit agreement was 47%. At December 31, 2007, BGE had $0.7 million in letters of credit outstanding under this agreement.

Failure by Constellation Energy, or BGE, to comply with these provisions could result in the acceleration of the maturity of the debt outstanding under these facilities. 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.

The BGE credit facility also contains usual and customary cross-default provisions that apply to defaults on debt by BGE over a specified threshold. The indenture pursuant to which BGE has issued and outstanding mortgage bonds provides that a default under any debt instrument issued under the 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.

Pursuant to Senate Bill 1, in June 2007, BondCo, a subsidiary of BGE, issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover deferred power purchase costs. We discuss Senate Bill 1 in *Business Environment Regulation Maryland Senate Bills 1 and 400* section and BondCo in more detail in *Note 4*.

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, 2007, 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.

At December 31, 2007, Constellation Energy had a total of $14,761.6 million in guarantees outstanding, of which $13,538.0 million related to our competitive supply activities. These amounts do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties. These guarantees are put into place in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. While the stated limit of these guarantees is $13,538.0 million, our calculated fair value of obligations for commercial transactions covered by these guarantees was $3,460.6 million at December 31, 2007. If the parent company was required to fund these subsidiary obligations, the total amount based on December 31, 2007 market prices would be $3,460.6 million. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets. We believe it is unlikely that we would be required to perform or incur any losses associated with guarantees of our subsidiaries' obligations.

We discuss our other guarantees in *Note 12* and our significant variable interests in *Note 4*.

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.

The Audit Committee of the Board of Directors periodically reviews compliance with our risk parameters, limits and trading guidelines, and our Board of Directors has established a value at risk limit. We have a Risk Management Division 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 Division 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 our Chief Risk Officer, and consists of our Chief Executive Officer, our Chief Financial Officer, our Executive Vice President of Corporate Strategy, the President of Constellation Energy Resources, the Chief Commercial Officers of Constellation Energy Resources, and the President of Constellation Energy Nuclear 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 $450.0 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 $450.0 million in interest rate swaps, approximately 16% of our long-term debt is floating-rate.

We discuss our use of derivative instruments to manage our interest rate risk in more detail in *Note 13*.

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

	2008	2009	2010	2011	2012	Thereafter	Total	Fair value at December 31, 2007
					(Dollars in millions)			
Long-term debt								
Variable-rate debt	$	$	$	$ 36.0	$ 255.2	$ 510.4	$ 801.6	$ 801.6
Average interest rate	%	%	%	3.77%	7.59%	4.09%	5.19%	
Fixed-rate debt	$ 355.6	$ 566.5	$ 56.9	$ 81.7	$ 624.1	$ 2,559.5(A)	$ 4,244.3	$ 4,307.5
Average interest rate	6.20%	6.09%	5.68%	5.95%	6.82%	6.18%	6.26%	

(A)

Amount excludes $339.8 million of long-term debt that is periodically remarketed and could require us to repay the debt prior to maturity of which $25.0 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 and our competitive supply operations, and our origination, risk management, and trading 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.

<u>Commodity Prices</u>

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,
- changes in the nature and extent of federal and state regulations, and
- geopolitical concerns affecting global supply of coal, oil, and natural gas.

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, uranium, 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, oil, 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. 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 facility and the Ginna facility sell 90% and 80% of their respective 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 and Trading

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 and purchases of 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 derivative assets and liabilities subject to mark-to-market accounting, 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 derivative assets and liabilities subject to mark-to-market accounting, 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 on the next page represent the potential pre-tax loss in the fair value of our wholesale marketing and risk management derivative assets and liabilities subject to mark-to-market accounting over one and ten-day holding periods.

Total Wholesale Value at Risk

For the year ended December 31,	**2007**	**2006**
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	**$ 20.4**	$ 13.4
Average	**15.4**	16.7
High	**26.8**	28.0
Low	**8.2**	9.6

95% Confidence Level, One-Day Holding Period