CONSTELLATION ENERGY GROUP INC
Form 10-K
March 03, 2006

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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, 2005**

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

MARYLAND

(States of incorporation)

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

410-783-2800
(Registrants' telephone number, including area code)

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

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

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

Not Applicable

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

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

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

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

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

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

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 30, 2005 was approximately $10,225,051,449 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE
178,454,929 SHARES OUTSTANDING ON JANUARY 31, 2006.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for the 2006 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, and emission allowances,
- the liquidity and competitiveness of wholesale markets for energy commodities,
- the effect of weather and general economic and business conditions on energy supply, demand, and prices,
- the ability to attract and retain customers in our competitive supply activities and to adequately forecast their energy usage,
- the timing and extent of deregulation of, and competition in, the energy markets, and the rules and regulations adopted in those markets,
- uncertainties associated with estimating natural gas reserves, developing properties, and extracting natural gas,
- regulatory or legislative developments that affect deregulation, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to nuclear power plants, safety, or environmental compliance,
- the inability of Baltimore Gas and Electric Company (BGE) to recover all its costs associated with providing electric residential customers service during or after the electric rate freeze period,
- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and BGE's ability to maintain their current credit ratings,
- the effectiveness of Constellation Energy's and BGE's risk management policies and procedures and the ability and willingness of our counterparties to satisfy their financial and performance commitments,
- operational factors affecting commercial operations of our generating facilities (including nuclear facilities) and BGE's transmission and distribution facilities, including catastrophic weather-related damages, unscheduled outages or repairs, unanticipated changes in fuel costs or availability, unavailability of coal or gas transportation or electric transmission services, workforce issues, terrorism, liabilities associated with catastrophic events, and other events beyond our control,
- the actual outcome of uncertainties associated with assumptions and estimates using judgment when applying critical accounting policies and preparing financial statements, including factors that are estimated in determining the fair value of energy contracts, such as the ability to obtain market prices and, in the absence of verifiable market prices, the appropriateness of models and model inputs (including, but not limited to, estimated contractual load obligations, unit availability, forward commodity prices, interest rates, correlation and volatility factors),
- changes in accounting principles or practices,
- losses on the sale or write down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets,
- cost and other effects of legal and administrative proceedings that may not be covered by insurance, including environmental liabilities, and
- the likelihood and timing of the completion of the pending merger with FPL Group, Inc. (FPL Group), the terms and conditions of any required regulatory approvals of the pending merger, and potential diversion of management's time and attention from our ongoing business during this time period.

Given these uncertainties, you should not place undue reliance on these forward looking statements. Please see the other sections of this report, including *Item 1A. Risk Factors*, 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

Pending Merger with FPL Group, Inc.

On December 18, 2005, Constellation Energy entered into an Agreement and Plan of Merger with FPL Group. The merger agreement has been unanimously approved by both companies' boards of directors but completion of the merger is contingent upon, among other things, the approval of the transaction by shareholders of both companies and receipt of required regulatory approvals. The companies anticipate obtaining all necessary approvals and completing the merger by the end of 2006. The merger agreement contains certain termination rights for both Constellation Energy and FPL Group, and further provides for the payment of fees upon termination of the merger agreement under specified circumstances. Further information concerning the pending merger will be included in the joint proxy statement/prospectus contained in the registration statement on Form S-4 to be filed by Constellation Energy in connection with the merger. For additional information related to the merger, see *Note 15 to the Consolidated Financial Statements*.

Overview

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

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

Our merchant energy business is a competitive provider of energy solutions for a variety of customers. It has electric generation assets located in various regions of the United States and provides energy solutions to meet customers' needs. Our merchant energy business focuses on serving the full energy and capacity requirements (load-serving) of, and providing other energy products and risk management services for various customers.

Our merchant energy business includes:

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

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

Our other nonregulated businesses:

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

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

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

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

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

Operating Segments

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

	Unaffiliated Revenues			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2005	81%	12%	6%	1%
2004	76	16	6	2
2003	68	20	8	4

	Net Income (1)			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2005	71%	25%	4%	%
2004	75	23	4	(2)
2003	66	24	9	1

	Total Assets			
	Merchant Energy	**Regulated Electric**	**Regulated Gas**	**Other Nonregulated**
2005	77%	16%	6%	1%
2004	71	20	7	2
2003	67	23	7	3

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

(1) Excludes income (loss) on discontinued operations in 2005, 2004, and 2003 and cumulative effects of changes in accounting principles in 2005 and 2003 as discussed in more detail in *Item 8. Financial Statements and Supplementary Data*.

Merchant Energy Business

Introduction

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

Constellation Energy Commodities Group, our wholesale marketing and risk management operation, dispatches the energy from our generating facilities and from some facilities with which we have power purchase agreements, manages the risks associated with selling the output and purchasing non-nuclear fuels, and enters into transactions to meet customers' energy and risk management requirements. This operation also trades energy and energy-related commodities and deploys risk capital in the management of our portfolio in order to earn additional returns. Constellation NewEnergy, our electric and gas retail operation, provides electricity, natural gas, transportation, and other energy services to commercial, industrial, and governmental customers.

Constellation Generation Group, our merchant generation operation, oversees the ownership, operations, maintenance, and performance of our fossil, nuclear and renewable generation and fuel processing facilities. Our generation capacity supports our wholesale and retail operations by providing a source of reliable power supply. Constellation Generation Group also owns and operates a generation operations and maintenance services organization.

Our merchant energy business:

provided service to distribution utilities, municipalities, commercial and industrial, and governmental customers with approximately 39,500 megawatts (MW) of peak load in the aggregate during 2005,

provided approximately 300,000 million British Thermal Units (mmBTUs) of natural gas to commercial, industrial, and governmental customers during 2005,

delivered 12.6 million tons of coal to international and domestic third-party customers and to our own fleet during 2005, and

managed approximately 11,850 MW of generation capacity.

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

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

Plants with Power Purchase Agreements our generating facilities outside the Mid-Atlantic Region with long-term power purchase agreements, including our Nine Mile Point Nuclear Station (Nine Mile Point), R.E. Ginna Nuclear Plant (Ginna), University Park, and High Desert generating facilities.

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

Retail Competitive Supply our operation that provides electric and 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.

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

Mid-Atlantic Region

We own 6,960 MW of fossil, nuclear, and hydroelectric generation capacity in the Mid-Atlantic Region. The output of these plants is managed by our wholesale marketing and risk management operation and is hedged through a combination of power sales to wholesale and retail market participants. 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, Big Sandy, and Wolf Hills facilities that commenced operations in mid-2001. The assets transferred from BGE are subject to the lien of BGE's mortgage.

Our merchant energy business provides power to enable BGE to provide standard offer service as discussed in the *Baltimore Gas and Electric Company Standard Offer Service* section. For 2005, the peak load supplied to BGE was approximately 4,000 MW.

Plants with Power Purchase Agreements

We own 3,189 MW of nuclear and natural gas generation capacity with power purchase agreements for their output. Our facilities with power purchase agreements consist of:

- the Nine Mile Point facility,
- the Ginna facility,
- the High Desert facility, and
- the University Park facility.

We own 100% of Nine Mile Point Unit 1 (620 MW) and 82% of Unit 2 (941 MW). The remaining interest in Nine Mile Point Unit 2 is owned by the Long Island Power Authority. Unit 1 entered service in 1969 and Unit 2 in 1988. Nine Mile Point is located within the New York Independent System Operator (NYISO) region.

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

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

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

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

In June 2004, we purchased the Ginna nuclear facility which is located in Ontario, New York from Rochester Gas & Electric Corporation (RG&E). Ginna consists of a 498 MW reactor that entered service in 1970 and is licensed to operate until 2029. The acquisition includes a long-term unit contingent power purchase agreement under which we sell up to 90% of the plant's output and capacity to RG&E for 10 years at an average price of $44.00 per MWH. The remaining output is managed by our wholesale marketing and risk management operation and sold into the wholesale market. We expect to increase the capacity of Ginna by 83 MW through a planned uprate in 2006.

The High Desert facility has a long-term power sales agreement with the California Department of Water Resources (CDWR). The agreement has a "tolling" feature, under which the CDWR pays a fixed amount of $12.1 million per month which provides CDWR the right, but not the obligation, to purchase power at a price linked to the variable cost of production. During the term of the agreement, which runs until January 2011, the facility will provide energy exclusively to the CDWR.

We have sold 100% of the output of the University Park facility under a tolling agreement ending May 31, 2006. Under this tolling agreement, our counterparty will pay a fixed amount per month and have the right, but not the obligation, to purchase power from us at prices linked to the variable fuel and other costs of production.

In the second quarter of 2005, we sold our Oleander generating facility. We discuss this sale in more detail in *Note 2 to the Consolidated Financial Statements.*

Competitive Supply

We are a leading supplier of energy products and services to wholesale customers and retail commercial and industrial customers. In 2005, our wholesale marketing and risk management operation provided approximately 24,000 peak MWs of wholesale full requirements load-serving products. During 2005, our retail competitive supply activities served approximately 15,500 MW of peak load and approximately 300,000 mmBTUs of natural gas. Our competitive supply activities also include 1,465 MW of capacity from our Rio Nogales and Holland Energy natural gas-fired generating facilities. These facilities are not sold forward under long-term agreements, and their output is used to serve customer requirements.

Wholesale and Retail Load-Serving Activities

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

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

- bilateral power purchase agreements with third parties,
- unit contingent purchases from generation companies,
- our generation assets,
- regional power pools, and
- tolling contracts with generation companies, which provide us the right, but not the obligation, to purchase power at a price linked to the variable cost of production, including fuel, with terms that generally extend from several months to several years but can be longer.

Portfolio Management and Trading

Our wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities, we trade energy and energy-related commodities 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 a variety of instruments, including:

- forward contracts (which commit us to purchase or sell energy commodities in the future),
- swap agreements (which require payments to or from counterparties based upon the difference between two prices for a predetermined contractual (notional) quantity),

- option contracts (which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price), and
- futures contracts (which are exchange traded standardized commitments to purchase or sell a commodity or financial instrument, or make a cash settlement, at a specified price and future date).

Active portfolio management allows our wholesale marketing and risk management operation 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 Services

Our wholesale marketing and risk management operation participates in global coal sourcing activities by providing coal and coal related logistical services, such as transportation for the variable or fixed supply needs of North American and international power generators. In 2005, we delivered 12.6 million tons of coal to international and domestic third- party customers and to our own fleet.

We also include in our coal services the results from our synthetic fuel processing facility in South Carolina.

Natural Gas Services

Our wholesale marketing and risk management operation provides products and services to upstream (exploration and production) and downstream (transportation and storage) natural gas customers, including large utilities, industrial customers, power generators, wholesale marketers, and retail aggregators.

In June 2005, we acquired working interests in gas producing fields in Texas and Alabama. We discuss this asset acquisition in more detail in *Note 15 to the 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 and are 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 a joint enterprise with AREVA, Inc., to develop a standardized fleet of nuclear power plants based on an advanced design called the U.S. Evolutionary Power Reactor (U.S. EPR). We intend to work with AREVA, Inc. to obtain design certification and all necessary approvals from the NRC to license, construct, own, and operate U.S. EPR plants. Unistar Nuclear will offer the business framework that could enable the development of future joint ventures with Constellation Energy, other energy companies, and interested parties. Those future joint ventures, in turn, would license, construct, own, and operate nuclear power plants as part of a standardized fleet. However, prior to identifying specific projects or committing to ordering new nuclear power plants, our financial commitment will be limited to the formation of the business platform and business development activities, including early-stage licensing and permit activities.

Fuel Sources

Our power plants use diverse fuel sources. Our fuel mix based on capacity owned at December 31, 2005 and our generation based on actual output by fuel type in 2005 were as follows:

Fuel	Capacity Owned	Generation
Nuclear	32%	52%
Coal	23	30
Natural Gas	31	14
Oil	6	1
Renewable and Alternative (1)	4	2
Dual (2)	4	1

(1) Includes solar, geothermal, hydro, and biomass.

(2) Switches between natural gas and oil.

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

Nuclear

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

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH*	Capacity Factor	MWH	Capacity Factor
	(MWH in millions)					
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
2002	12.1	82	11.7	87	3.8	89
2001	13.6	92	11.6	86	4.3	100

*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 for sufficient quantities of uranium (concentrates and uranium hexafluoride) to meet 100% of our total requirements through 2008. Additionally, we have commitments covering approximately 80% of our requirements in 2009 and 85% in 2010.
Enrichment	We have commitments that provide 100% of our uranium enrichment requirements through 2010 and 25% of these requirements in 2011 and 2012.

Fuel Assembly Fabrication	We have commitments for the fabrication of fuel assemblies for reloads required through 2013 for Nine Mile Point and Calvert Cliffs Nuclear Power Plant, Inc. (Calvert Cliffs), and through 2017 for Ginna.

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

Storage of Spent Nuclear Fuel Federal Facilities

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

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

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

In connection with our purchase of Ginna, all of RG&E's rights and obligations related to recovery of damages from the DOE were assigned to us. However, we have an obligation to reimburse RG&E for up to the first $10 million of any recovered damages.

Storage of Spent Nuclear Fuel On-Site Facilities

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

Cost for Decommissioning Uranium Enrichment Facilities

The Energy Policy Act of 1992 requires domestic nuclear utilities to contribute to a fund for decommissioning and decontaminating uranium enrichment facilities that had been operated by DOE. These contributions are generally payable over a 15-year period with escalation for inflation and are based upon the amount of uranium enriched by DOE for each utility through 1992. The 1992 Act provides that these costs are recoverable through utility service rates. BGE is solely responsible for these costs as they relate to Calvert Cliffs and will make the last payment in 2006. The sellers of the Nine Mile Point plant and the Long Island Power Authority are responsible for the costs relating to the Nine Mile Point plant. The seller of Ginna is responsible for the costs related to that facility.

Cost for Decommissioning

We are obligated to decommission our nuclear plants at the time these plants cease operation. Every two years, the NRC requires us to demonstrate reasonable assurance that funds will be available to decommission the sites. When BGE transferred all of its nuclear generating assets to our merchant energy business, it also transferred the trust fund established to pay for decommissioning Calvert Cliffs. At December 31, 2005, the trust fund assets were $370.4 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 of approximately $18.7 million until June 30, 2006, and thereafter in an annual amount determined by reference to specified factors. We are required to submit a filing to the Maryland PSC by April 2006 to determine the annual amount BGE ratepayers will pay, if any, for decommissioning Calvert Cliffs after June 30, 2006. BGE is collecting this amount on behalf of Calvert Cliffs. Any costs to decommission Calvert Cliffs in excess of this $520 million must be paid by Calvert Cliffs. If BGE ratepayers have paid more than this amount at the time of decommissioning, Calvert Cliffs must refund the excess. If the cost to decommission Calvert Cliffs is less than the $520 million BGE's ratepayers are obligated to pay, Calvert Cliffs may keep the difference.

The sellers of Nine Mile Point transferred a $441.7 million decommissioning trust fund to us at the time of sale. In return, we assumed all liability for the costs to decommission Unit 1 and 82% of the costs to decommission Unit 2. We believe that this amount is adequate to cover our responsibility for decommissioning Nine Mile Point to a greenfield status (restoration of the site so that it substantially matches the natural state of the surrounding properties and the site's intended use). At December 31, 2005, the Nine Mile Point trust fund assets were $518.3 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, 2005, the Ginna trust fund assets were $222.0 million.

Coal

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

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

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

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

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

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

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

Gas

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

Oil

Under normal burn practices, our requirements for residual fuel oil (No. 6) amount to approximately 1.5 million to 2.0 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor 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

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

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

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

States are considering different types of regulatory initiatives concerning competition in the power 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. While many states continue to support retail competition and industry restructuring, other states that were considering deregulation have slowed their plans or postponed consideration of deregulation. In addition, other states are reconsidering deregulation.

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

As the market for commercial and industrial supply continues to grow, we have experienced increased competition on a regional basis in our retail commercial and industrial supply activities. The increase in retail competition and the impact of wholesale power prices compared to the rates charged by local utilities 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

		2005		2004		2003		2002		2001
Revenues *(In millions)*										
Mid-Atlantic Region	**$**	**2,283.9**	$	1,925.6	$	1,696.2	$	1,415.1	$	1,379.2
Plants with Power Purchase Agreements		**829.6**		714.5		574.6		433.2		70.8
Competitive Supply Retail		**6,942.3**		4,280.0		2,567.7		312.7		
Competitive Supply Wholesale		**4,672.3**		3,353.8		2,703.9		540.7		233.5
Other		**58.0**		73.6		45.1		56.4		80.5
Total Revenues	**$**	**14,786.1**	$	10,347.5	$	7,587.5	$	2,758.1	$	1,764.0
Generation *(In millions)* MWH		**60.2**		55.3		51.6		44.7		37.4

Operating statistics do not reflect the elimination of intercompany transactions.

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

Baltimore Gas and Electric Company

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

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

BGE's electric and gas revenues come from many customers residential, commercial, and industrial.

Electric Business

Electric Regulatory Matters and Competition

Deregulation

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

All customers can choose their electric energy supplier.

BGE provided fixed-price standard offer service for commercial and industrial customers through either June 30, 2002 or June 30, 2004, depending on customer type. For the commercial and industrial customers that did not select an alternative supplier after those time periods, BGE provided a market-based standard offer service. Base rates for commercial and industrial customers were frozen until June 30, 2004.

Commercial and industrial customers have several service options that fix competitive transition charges (CTC) through June 30, 2006, at which time the CTC will be phased-out. CTC revenues were provided to allow BGE to recover stranded costs that resulted from the deregulation of BGE's generating assets.

BGE residential base rates for delivery service will not change before July 2006. Total residential base rates remain unchanged over the initial transition period (July 1, 2000 through June 30, 2006), as annual standard offer service rate increases are offset by corresponding decreases in the CTC that BGE receives from its customers.

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

BGE transferred, at book value, its generating assets and related liabilities to the merchant energy business. At December 31, 2005, BGE remains contingently liable for the $269.8 million outstanding balance for liabilities transferred to the merchant energy business.

Standard Offer Service

BGE is providing fixed-price standard offer service for residential customers that do not select an alternative supplier through June 30, 2006. Beginning July 1, 2006, BGE's obligation to provide fixed-price standard offer service to residential customers will end, and all residential customers that receive their electric supply from BGE will be charged market-based standard offer service rates.

Since July 1, 2004, all commercial and industrial customers that receive their electric supply from BGE are charged market-based standard offer service rates. We discuss market-based standard offer service in more detail below.

Provider of Last Resort (POLR)
BGE is obligated to provide market-based standard offer service to residential customers from July 1, 2006 through May 31, 2010, and for commercial and industrial customers for varying periods beyond June 30, 2004, depending on customer load. The POLR rates charged during these time periods 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.

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.

In September 2005, the Maryland PSC issued an order extending POLR service through May 2007 for those commercial and industrial customers for which market-based standard offer service was scheduled to expire at the end of May 2006. The extended service will be provided on substantially the same terms as under the existing service, except that wholesale bidding for service to some customers will be conducted more frequently.

Bidding to supply BGE's market-based standard offer service to commercial and industrial customers beyond May 31, 2006, and to residential customers beyond June 30, 2006, will occur from time to time through a competitive bidding process approved by the Maryland PSC. Successful bidders, which may include subsidiaries of Constellation Energy, will execute contracts with BGE for varying terms depending on the load being served under the contract.

In early 2006, the Maryland PSC commenced a proceeding, and legislation was introduced in the Maryland General Assembly, to consider methods for requiring BGE to defer recovery of some of its costs of providing residential POLR service. These actions are a result of the anticipated increase in POLR prices expected to take place upon the expiration of the residential rate freeze in June 2006. Any decision by the Maryland PSC or legislation adopted by the Maryland General Assembly, that would defer recovery of, or would not allow BGE to fully recover its costs could have a material impact on our, and BGE's, financial results and liquidity.

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

Electric Load Management

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

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

These programs generally take effect on summer days when demand and/or wholesale prices are relatively high and had the capability during the 2005 summer to reduce load up to approximately 238 MW.

Transmission and Distribution Facilities

BGE maintains approximately 250 substations and 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains approximately 23,600 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

	2005	2004	2003	2002	2001
Revenues *(In millions)*					
Residential	**$ 1,066.6**	$ 1,015.8	$ 959.0	$ 946.6	$ 885.3
Commercial					
Excluding Delivery Service Only	**722.1**	708.9	694.2	776.0	903.0
Delivery Service Only	**107.5**	78.6	66.1	33.5	
Industrial					
Excluding Delivery Service Only	**52.8**	92.3	137.0	158.7	218.1
Delivery Service Only	**28.0**	21.3	18.2	10.9	
System Sales and Deliveries	**1,977.0**	1,916.9	1,874.5	1,925.7	2,006.4
Other (A)	**59.5**	50.8	47.1	40.3	33.6
Total	**$ 2,036.5**	$ 1,967.7	$ 1,921.6	$ 1,966.0	$ 2,040.0
Distribution Volumes (*In thousands*) MWH					
Residential	**13,762**	13,313	12,754	12,652	11,714
Commercial					
Excluding Delivery Service Only	**7,847**	9,286	9,937	11,840	14,147
Delivery Service Only	**7,967**	5,767	4,982	2,762	
Industrial					
Excluding Delivery Service Only	**614**	1,429	2,556	3,478	4,445
Delivery Service Only	**3,122**	2,562	1,780	997	
Total	**33,312**	32,357	32,009	31,729	30,306
Customers *(In thousands)*					
Residential	**1,084.1**	1,072.1	1,061.7	1,052.3	1,040.5
Commercial	**114.7**	113.6	112.1	110.8	110.9
Industrial	**5.0**	4.8	4.9	4.9	5.0
Total	**1,203.8**	1,190.5	1,178.7	1,168.0	1,156.4

(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 April 2005, BGE filed an application for a $52.7 million annual increase in its gas base rates. The Maryland PSC issued an order in December 2005 granting BGE an annual increase of $35.6 million. Certain parties to the proceeding have sought judicial review and Maryland PSC rehearing of the decision. BGE will not seek review of any aspect of the order. We cannot provide assurance that a court will not reverse any aspect of the order or that it will not remand certain issues to the Maryland PSC.

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 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 2006 to 2028.

BGE's current pipeline firm transportation entitlements to serve BGE's firm loads are 309,053 dekatherms (DTH) per day.

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

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

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

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

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

Gas Operating Statistics

	2005	2004	2003	2002	2001
Revenues *(In millions)*					
Residential					
Excluding Delivery Service Only	**$ 558.5**	$ 478.0	$ 444.5	$ 342.1	$ 378.4
Delivery Service Only	**23.2**	14.2	13.6	16.5	16.3
Commercial					
Excluding Delivery Service Only	**174.4**	135.4	128.6	89.4	115.5
Delivery Service Only	**31.9**	28.0	24.6	29.2	21.4
Industrial					
Excluding Delivery Service Only	**10.5**	9.4	11.5	9.3	12.8
Delivery Service Only	**12.4**	7.8	11.4	13.9	13.8
System Sales and Deliveries	**810.9**	672.8	634.2	500.4	558.2
Off-System Sales	**154.7**	77.2	84.8	74.8	113.6
Other	**7.2**	7.0	7.0	6.1	8.9
Total	**$ 972.8**	$ 757.0	$ 726.0	$ 581.3	$ 680.7
Distribution Volumes *(In thousands)* DTH					
Residential					
Excluding Delivery Service Only	**39,107**	39,080	40,894	35,364	33,147
Delivery Service Only	**5,423**	6,053	6,640	6,404	7,201
Commercial					
Excluding Delivery Service Only	**14,133**	13,248	13,895	11,583	12,334
Delivery Service Only	**28,993**	34,120	29,138	28,429	25,037
Industrial					
Excluding Delivery Service Only	**921**	865	1,143	1,207	1,386
Delivery Service Only	**19,357**	14,310	18,399	23,689	23,872
System Sales and Deliveries	**107,934**	107,676	110,109	106,676	102,977
Off-System Sales	**17,209**	9,914	12,859	18,551	20,012
Total	**125,143**	117,590	122,968	125,227	122,989
Customers *(In thousands)*					
Residential	**590.9**	582.0	575.2	567.3	558.7
Commercial	**42.0**	41.6	41.1	40.7	40.2
Industrial	**1.2**	1.2	1.2	1.3	1.4
Total	**634.1**	624.8	617.5	609.3	600.3

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 them to engage in their present business. Conditions of the franchises are satisfactory.

Other Nonregulated Businesses

Energy Projects and Services

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

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

Home Products and Gas Retail Marketing

We offer services to customers in Maryland including:

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

Other

Our other nonregulated businesses include investments that we do not consider to be core operations. These include financial investments and real estate projects. While our intent is to dispose of these assets, market conditions and other events beyond our control may affect the actual sale of these assets. However, a future decline in the fair value of these assets could result in losses.

In the fourth quarter 2005, we sold our interests in our Panamanian distribution facility and the fund that holds interests in two South American energy projects. We discuss this sale in more detail in *Note 2 to the Consolidated Financial Statements.*

Consolidated Capital Requirements

Our total capital requirements for 2005 were $1,032 million. Of this amount, $741 million was used in our nonregulated businesses and $291 million was used in our regulated business. We estimate our total capital requirements will be $1,345 million in 2006.

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

Environmental Matters

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

We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain on-going compliance. Our capital expenditures were approximately $170 million during the five-year period 2001-2005 to comply with existing environmental standards and regulations. Our estimated environmental capital requirements for the next three years are approximately $40 million in 2006, $200 million in 2007, and $330 million in 2008.

Air Quality

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

National Ambient Air Quality Standards (NAAQS)

The NAAQS are federal air quality standards that establish maximum ambient air concentrations for the following specific pollutants: ozone (smog), carbon monoxide, lead, particulates, sulfur dioxides (SO_2), and nitrogen dioxides (NO_2). Our generating facilities are primarily affected by ozone and particulates standards. Ozone is formed when sunlight interacts with emissions of nitrogen oxides (NO_x) and volatile organic compounds (such as from motor vehicle exhaust). Our generating facilities are subject to various permits and programs meant to achieve or preserve attainment of the standards for all these pollutants.

In order for states to achieve compliance with the NAAQS, 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 NO_x emissions from fossil fuel-fired generating facilities located primarily in the Eastern United States. The NO_x reduction requirements will be phased-in starting in 2009 with both annual and ozone season reduction requirements. The phase-in will be complete by 2015. The SO_2 reduction requirements will be phased-in starting in 2010 with the phase-in complete by 2015. According to the EPA, when fully implemented, CAIR will reduce SO_2 emissions in the affected states by over 70 percent and reduce NO_x emissions by over 60 percent from 2003 levels. Although CAIR provides the overall reduction requirements for SO_2 and NO_x, we do not yet know the impact on our facilities as that will be determined by the affected states in which our facilities operate.

Based on the information currently available to us about CAIR, we will install additional air emission control equipment at our coal-fired generating facilities in Maryland and at our co-owned coal-fired facilities in Pennsylvania to meet air quality standards. We include in our estimated environmental capital requirements capital spending for these projects, which we expect will be approximately $40 million in 2006, $185 million in 2007, $300 million in 2008 and $200 million from 2009-2010. Our estimates are subject to significant uncertainties including the timing of any additional federal and/or state regulations or legislation, 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. In addition, CAIR is subject to legal challenges filed by the states and industry and environmental groups. We cannot predict the timing or outcome of these challenges, or their possible effect on our financial results.

In May 2005, the EPA adopted a stricter NAAQS for ozone. States will be required to submit plans to the EPA to meet the new standard by 2007, at which time the standard will take effect. We are unable to determine the impact that complying with the stricter NAAQS for ozone will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standard. In transitioning to the stricter NAAQS for ozone, the EPA has delayed the requirement that states impose fees on generating facilities located in areas that have not met the NAAQS for ozone. Such fees could have been assessed on certain of our generating facilities located in Maryland and California beginning in 2006, but now will not be assessed prior to 2010.

In June 2005, the EPA finalized its rules relating to regional haze, which address emissions of SO_2, NO_x, and particulate matter. However, adoption of CAIR by states is expected to meet the emissions reduction requirements under the regional haze rules. We expect Maryland and Pennsylvania, where we own several generating facilities, will, at a minimum, adopt CAIR. As a result, we believe the adoption of the regional haze rules by the EPA will not have a material effect on our financial results.

Several states in the northeastern U.S., including Maryland, continue to advocate for more stringent and earlier SO_2 and NO_x emissions reductions than those required under CAIR, the Clean Air Mercury Rule (CAMR), or other federally proposed legislative initiatives (such as the Bush Administration's Clear Skies proposal). These states have argued that such additional reductions are necessary to achieve compliance with the NAAQS for ozone and fine particulate matter by 2010.

In January 2006, the Maryland Department of the Environment (MDE) proposed the Clean Power Rule (CPR). In addition, a bill entitled the Healthy Air Act (HAA) was introduced in both houses of the Maryland legislature in January 2006. The CPR and the HAA would require more stringent and earlier reductions of SO_2, NO_x and mercury than required by CAIR and CAMR. The HAA also contains provisions for the reduction of carbon dioxide (CO_2) from coal-fired power plants in Maryland based upon concerns over global climate change. We are currently evaluating the potential impact of the CPR and the HAA on our environmental capital expenditure estimates and our financial results. While we do not know whether the CPR or the HAA will be enacted; if either is enacted, our compliance costs could be material.

Hazardous Air Emissions

The Clean Air Act requires the EPA to evaluate the public health impacts of hazardous air emissions from electric steam generating facilities. In March 2005, the EPA finalized regulations to reduce the emissions of mercury from coal-fired facilities. Under CAMR, the EPA has decided to regulate mercury through a market-based cap and trade program that will reduce nationwide utility emissions of mercury in two phases. The final CAMR does not address emissions of nickel and the EPA has not re-proposed regulating such emissions. The first phase of the program will begin in 2010. Additional mercury reductions will be required in the second phase of the program starting in 2018. According to the EPA, the CAMR will reduce mercury emissions from all affected coal-fired power plants by about 19 percent from 1999 levels in 2010, mostly from controls installed to comply with CAIR. The EPA expects total mercury reductions from all affected coal-fired plants of about 69 percent from 1999 levels by 2018.

The CAMR will affect all coal or waste coal fired boilers at our generating facilities. Although our planned capital expenditures for compliance with CAIR are anticipated to enable us to substantially meet the mercury reduction requirements under the first phase of the cap and trade program, the overall cost of compliance with the CAMR, including complying with the requirements under the second phase of the program, could be material. CAMR is subject to legal challenges filed by the states, industry, and environmental groups. We cannot predict the timing or outcome of these challenges, or their possible effect on our financial results. As discussed on the previous page, regulatory (CPR) and legislative proposals (HAA) in Maryland would require more stringent and earlier mercury reductions than required by CAMR. We are currently evaluating the potential impact of CAMR, CPR, and HAA on our financial results and on our environmental capital expenditure estimates.

New Source Review

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

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

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

Global Climate Change

Future initiatives regarding greenhouse gas emissions and global warming continue to be the subject of much debate. As a result of our diverse fuel portfolio, our contribution to greenhouse gases varies by plant type. Fossil fuel-fired power plants are significant sources of CO_2 emissions, a principal greenhouse gas. Our compliance costs with any mandated federal greenhouse gas reductions in the future could be material.

Water Quality

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

Water Intake Regulations

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

Hazardous and Solid Waste

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

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

Our coal-fired generating facilities produce approximately two and a half million tons of combustion by-products ("ash") each year, including approximately 850,000 tons at our Maryland plants. Of the two and a half million tons, approximately 75% is beneficially re-used in various projects, including as structural fill in surface mine reclamation, and the remainder is placed in landfills. In 2000, the EPA decided not to regulate combustion ash as a hazardous waste under RCRA. Instead, the EPA announced its intention to develop national standards, currently scheduled to be proposed in June 2006, to regulate this material as a non-hazardous waste, and is developing regulations governing the placement of ash in landfills, surface impoundments, and sand/gravel surface mines. The EPA is also developing regulations for ash placement in coal mines, which are expected to be proposed in October 2007. Federal regulation has the potential to result in additional requirements such as groundwater monitoring, liners, and leachate collection and treatment systems for all landfills, surface impoundments, and sand and gravel mines used for ash management. Depending on the scope of any final requirements, our compliance costs could be material.

As a result of these regulatory proposals, the remaining ash placement capacity at our current mine reclamation site and our current ash generation projections, we are exploring our options for the placement of ash, including construction of an ash placement facility. Over the next five years, we estimate that our capital expenditures for this project will be 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 9,850 employees at December 31, 2005. At the Nine Mile Point facility, approximately 680 employees are represented by the International Brotherhood of Electrical Workers, Local 97. The labor contract with this union expires in June 2006. We expect negotiations for a new contract to begin in May 2006. We expect to execute a new agreement with the union. 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 as a result of its participation in the wholesale energy markets.

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 operate 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. In addition, our business depends upon transmission facilities owned and operated by others; if transmission is disrupted or capacity is inadequate or unavailable, our ability to sell and deliver our wholesale power may be limited.

Currently, our power generation facilities purchase a portion of their fuel through short-term contracts or on the spot market. Fuel prices may also be volatile, and the price that can be obtained for power sales may not change at the same rate as changes in fuel costs. Also, our competitive energy businesses expose us to other risks, including credit risk and other risks relating to counterparties' failure to perform, and to the risk of commodity price fluctuations. Fuel price increases and defaults by suppliers and other counterparties may adversely affect our financial results.

Volatility in market prices for fuel and electricity may result from among other things:

- weather conditions,
- seasonality,
- electricity usage,
- illiquid markets,
- transmission or transportation constraints or inefficiencies,
- availability of competitively priced alternative energy sources,
- demand for energy commodities,
- available supplies of natural gas, crude oil and refined products, and coal,
- generating unit performance,
- natural disasters, terrorism, wars, embargoes and other catastrophic events,
- federal and state energy and environmental regulation, legislation and policies,
- geopolitical concerns affecting global supply of oil and natural gas, and
- general economic conditions, including downturns in the United States economy, which impact energy consumption.

In addition to the risks discussed above, risks specifically affecting our success in competitive wholesale markets include the ability to efficiently operate generating assets, maintenance of the qualifying facility status of certain projects, transmission and transportation availability, competition from new sources of generation, and the level of generation capacity. Our inability or failure to effectively hedge our assets or positions against changes in commodity prices, interest rates, counterparty credit risk, or other risk measures could significantly impact our future financial results.

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

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, the Environmental Protection Agency (EPA) recently adopted the Clean Air Interstate Rule (CAIR), which requires further reductions of sulfur dioxide and nitrogen oxide emissions from fossil fuel-fired plants located primarily in the Eastern United States, where many of our plants are located, and the Clean Air Mercury Rule (CAMR), which will regulate mercury emissions from coal-fired plants through a cap and trade program. In addition, the State of Maryland is considering requiring additional requirements to further reduce emissions of sulfur dioxide, nitrogen oxide, carbon dioxide, and mercury from generating facilities located in that state. Because CAIR and CAMR are still in the process of being implemented by the affected states and the additional Maryland requirements are in the proposal stage, we do not yet know the precise impact on our financial results. The capital expenditures and compliance costs with new air emission standards could be significantly greater than currently estimated.

The EPA also issued a rule under the Clean Water Act that will require certain of our plants to implement "best technology available" to minimize adverse effects to fish and shellfish from cooling water intake structures at those plants. The capital expenditures and compliance costs with the Clean Water Act intake requirements could be material to our financial results.

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.

We are exposed to risks relating to the ownership and operation of nuclear power plants.

We own and operate nuclear power plants. Ownership and operation of these plants expose us to risks in addition to those that result from owning and operating non-nuclear power generation facilities. Risks associated specifically with the operation and cost of operation of nuclear plants include changing federal and state environmental requirements relating specifically to nuclear facilities, safety, terrorism, accidents at the nuclear plants, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and waste, monitoring of discharges into the environment, and any required remediation of any site that is identified as contaminated.

Any of these risks could result in substantial liabilities or expenses for us and reduce our earnings or harm our liquidity. In addition, the Nuclear Regulatory Commission (NRC) has the authority to modify, suspend or revoke the operating license for any of our nuclear power facilities if it determines that such action is necessary to ensure the public health and safety. Such action would have a negative impact on our financial results.

In the event of a nuclear accident at one of our nuclear plants, the cost of property damage and other expenses incurred may exceed our insurance coverage available from both private sources and an industry mutual insurance company. 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. Uninsured losses or the payment of retrospective insurance premiums could each have a material adverse effect on our financial results.

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

Under the electric restructuring the state of Maryland enacted in 1999 and various settlements approved by the Maryland Public Service Commission (Maryland PSC) in 2003 and 2005, BGE is obligated to serve as the POLR for all retail customers in its service territories for various periods ending between 2007 and 2010. POLR obligations are the obligations of energy delivery businesses to provide electricity to customers that do not choose a competitive supplier and, by their nature, are difficult to quantify.

As the POLR supplier, BGE is required to secure load requirements through a wholesale bidding process sufficient to serve those customers in its service territory in the event that customers do not choose alternate suppliers or if a third-party supplier is unable to satisfy its obligations. The settlements provide that BGE be able to recover all of its supply and certain other actual costs of providing POLR service.

However, in early 2006, the Maryland PSC commenced a proceeding, and legislation was introduced in the Maryland General Assembly, to consider methods for requiring BGE to defer recovery of some of its costs of providing residential POLR service. These actions are a result of the anticipated increase in POLR prices expected to take place upon the expiration of the residential rate freeze in June 2006. Any decision by the Maryland PSC, or legislation adopted by the Maryland General Assembly, that would defer recovery of, or would not allow BGE to fully recover its costs could have a material impact on our financial results and liquidity.

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.

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. While we have seen recent improvements in liquidity, future reductions in liquidity may restrict our ability to manage our risks, and 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.

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.

We are exposed to the risk of loss from counterparties' nonperformance. Nonperformance could be failure to provide energy or failure to pay for energy we provide a counterparty. Should counterparties fail to provide energy, we might be forced to enter into alternative arrangements or honor the underlying commitment at then-current market prices, which may result in higher costs to us. If the counterparties fail to pay for energy we provided, then our liquidity and financial results may be negatively impacted.

In connection with our operations, we have, and will continue to, guarantee or indemnify the performance of a portion of the obligations of our subsidiaries. Some of these guarantees and indemnities are for fixed amounts, others have a fixed maximum amount, and others do not specify a maximum amount. We might not be able to satisfy all of these guarantees and indemnification obligations if they were to come due at the same time.

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

The regulatory environment applicable to the electric and gas industries has undergone substantial changes over the past several years 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 gas industries and the manner in which their participants conduct business. We have targeted the deregulated segments of the electric and gas industries created by these initiatives. These changes are ongoing and we cannot predict the future development of deregulation in these markets or the ultimate effect that this changing regulatory environment will have on our business.

Moreover, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, and future changes in laws and regulations may have a detrimental effect on our business. Certain restructured markets (most notably California) have experienced supply problems and price volatility in the past. These supply problems and volatility have been the subject of a significant amount of publicity, much of which has been critical of the restructuring initiatives. In some of these markets, including California, proposals have been made by governmental agencies and/or other interested parties to re-regulate areas of these markets which have previously been deregulated. Other proposals to re-regulate may be made and legislative or other attention to the electric and gas restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric and gas markets is reversed, discontinued or delayed, 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 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. The Federal Energy Regulatory Commission (FERC) requires wholesale electric transmission services to be offered on an open access, non-discriminatory basis. However, sufficient transmission services are not always available. If transportation or transmission is disrupted, or transportation or transmission capacity is inadequate, our ability to sell and deliver products may be hindered. Such disruptions could also hinder our providing electricity or natural gas to our retail electric and gas customers 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 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.

Our business is affected by seasonal weather conditions. Consequently, 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.

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, and the amount of debt as a component of total capitalization.

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

We are subject to regulation under environmental laws, the Federal Power Act, the Atomic Energy Act of 1954 and the Energy Policy Act of 2005, and certain sections of Maryland and other state statutes relating to public utilities, and the operation of electric or natural gas facilities. Changing governmental policies and regulatory actions can have a significant impact on us, including those of FERC, the NRC, the Maryland PSC, and the utility commissions of other states in which we have operations. State and Federal regulations can impact, among other things, the following:

- allowed rates of return,
- industry and rate structure,
- operation of nuclear power plants,
- operation and construction of plant facilities,
- operation and construction of transmission facilities,
- acquisition, disposal, depreciation and amortization of assets and facilities,
- transactions between subsidiaries and affiliates,
- recovery of fuel and purchased power costs,
- recovery of storm-related repair costs,
- decommissioning costs,
- return on common equity and equity ratio limits,
- payment of dividends, and
- present or prospective wholesale and retail competition (including but not limited to retail choice and transmission costs).

Certain regulatory commissions also have the authority to disallow recovery of any and all costs that they consider excessive or imprudently incurred. In addition, BGE holds franchise agreements with local municipalities and counties, and must renegotiate expiring agreements. These factors may have a negative impact on our business and financial results.

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

As a result, the regulatory process may restrict our ability to grow earnings in certain parts of our business, can cause delays in or affect business planning and transactions, can increase our costs, and does not provide any assurance as to achievement of earnings levels.

We operate in a changing market environment influenced by various legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the energy industry, including deregulation of the production and sale of electricity. We will need to adapt to these changes, which could restrict our ability to continue to grow our nonregulated businesses. In addition, we may face increasing competitive pressures in our nonregulated businesses.

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, 2005, our qualified pension obligations were $345.1 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 affect 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 do not know the impact that any potential 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.

We may be unable to obtain the approvals required to complete our merger with FPL Group Inc. (FPL Group) or, in order to do so, the combined company may be required to comply with material restrictions or conditions.

On December 19, 2005, we announced the execution of a merger agreement with FPL Group. Before the merger may be completed, shareholder approval will have to be obtained by us and by FPL Group. In addition, various filings must be made with FERC, NRC and various utility regulatory, antitrust and other authorities in the United States. These governmental authorities may impose conditions on the completion, or require changes to the terms, of the merger, including restrictions or conditions on the business, operations, or financial performance of the combined company following completion of the merger. These conditions or changes could have the effect of delaying completion of the merger or imposing additional costs on or limiting the revenues of the combined company following the merger, which could have a material adverse effect on the financial results of the combined company and/or cause either us or FPL Group to abandon the merger.

If we are unable to complete the merger, we still will incur and will remain liable for significant transaction costs, including legal, accounting, financial advisory, filing, printing and other costs relating to the merger whether or not it is completed, which we estimate to be approximately $40 million. Also, depending upon the reasons for not completing the merger, including whether we have received or entered into a competing takeover proposal, we may be required to pay FPL Group a termination fee of up to $425 million. The occurrence of either of these events individually or in combination could have a material adverse affect on our financial results.

If completed, our merger with FPL Group may not achieve its intended results.

We and FPL Group entered into the merger agreement with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies primarily relating to the nonregulated businesses. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Constellation Energy and FPL Group are integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management's time and energy and could have an adverse effect on the combined company's business, financial results and prospects.

We will be subject to business uncertainties and contractual restrictions while the merger with FPL Group is pending that could adversely affect our financial results.

Uncertainty about the effect of the merger with FPL Group on employees and customers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our financial results could be affected.

The pursuit of the merger and the preparation for the integration of Constellation Energy and FPL Group may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could affect our financial results.

In addition, the merger agreement restricts us, without FPL Group's consent, from making certain acquisitions and taking other specified actions until the merger occurs or the merger agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the merger agreement.

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Item 2. Properties

Constellation Energy's corporate offices occupy approximately 106,000 square feet of leased office space in Baltimore, Maryland. The corporate offices for most of our merchant energy business occupy approximately 224,000 square feet of leased office space in another building in Baltimore, Maryland. We describe our electric generation properties on the next page. We also have leases for other offices and services located in the Baltimore metropolitan region, and for various real property and facilities relating to our generation projects.

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

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

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

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

All of BGE's property is subject to the lien of BGE's mortgage securing its mortgage bonds. All of the generation facilities transferred to 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 believe we have satisfactory title to our power project facilities in accordance with standards generally accepted in the energy industry, subject to exceptions, which in our opinion, would not have a material adverse effect on the use or value of the facilities.

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

The following table describes our generating facilities:

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel
			(at December 31, 2005)		
Mid-Atlantic Region					
Calvert Cliffs	Calvert Co., MD	1,735	100.0	1,735	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,286	100.0	1,286	Coal
H. A. Wagner	Anne Arundel Co., MD	1,001	100.0	1,001	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	358 (A)	Coal
Conemaugh	Indiana Co., PA	1,711	10.6	181 (A)	Coal
Perryman	Harford Co., MD	360	100.0	360	Oil/Gas
Big Sandy	Neal, WV	300	100.0	300	Gas
Wolf Hills	Bristol, VA	250	100.0	250	Gas
Riverside	Baltimore Co., MD	249	100.0	249	Oil/Gas
Handsome Lake	Rockland Twp, PA	250	100.0	250	Gas
Notch Cliff	Baltimore Co., MD	128	100.0	128	Gas
Westport	Baltimore City, MD	121	100.0	121	Gas
Philadelphia Road	Baltimore City, MD	64	100.0	64	Oil
Safe Harbor	Safe Harbor, PA	416	66.7	278	Hydro
Total Mid-Atlantic Region		9,981		6,960	
Plants with Power Purchase Agreements					
High Desert	Victorville, CA	830	100.0	830	Gas
Nine Mile Point Unit 1	Scriba, NY	620	100.0	620	Nuclear
Nine Mile Point Unit 2	Scriba, NY	1,148	82.0	941	Nuclear
R.E. Ginna	Ontario, NY	498	100.0	498	Nuclear
University Park	Chicago, IL	300	100.0	300	Gas
Total Plants with Power Purchase Agreements		3,396		3,189	
Competitive Supply					
Rio Nogales	Seguin, TX	800	100.0	800	Gas
Holland Energy	Shelby Co., IL	665	100.0	665	Gas
Total Competitive Supply		1,465		1,465	
Other					
Panther Creek	Nesquehoning, PA	83	50.0	42	Waste Coal
Colver	Colver Township, PA	110	25.0	28	Waste Coal
Sunnyside	Sunnyside, UT	53	50.0	26	Waste Coal
ACE	Trona, CA	102	31.1	32	Coal
Jasmin	Kern Co., CA	33	50.0	17	Coal
POSO	Kern Co., CA	33	50.0	17	Coal
Mammoth Lakes G-1	Mammoth Lakes, CA	6	50.0	3	Geothermal
Mammoth Lakes G-2	Mammoth Lakes, CA	12	50.0	6	Geothermal
Mammoth Lakes G-3	Mammoth Lakes, CA	12	50.0	6	Geothermal
Soda Lake I	Fallon, NV	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	22	45.0	10	Biomass
Malacha	Muck Valley, CA	32	50.0	16	Hydro
SEGS IV	Kramer Junction, CA	30	12.2	4	Solar
SEGS V	Kramer Junction, CA	30	4.2	1	Solar
SEGS VI	Kramer Junction, CA	30	8.8	3	Solar
Total Other		650		242	
Total Generating Facilities		15,492		11,856	

Plant	Location	Installed Capacity (MW)	% Owned	Capacity Owned (MW)	Primary Fuel

(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 following table describes our processing facilities:

Plant	Location	% Owned	Primary Fuel
A/C Fuels	Hazelton, PA	50.0	Coal Processing
Gary PCI	Gary, IN	24.5	Coal Processing
Low Country	Cross, SC	99.0	Synfuel Processing
PC Synfuel VA I	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

Item 3. Legal Proceedings

We discuss our legal proceedings in *Note 12 to the 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	51	Chairman of the Board of Constellation Energy (since July 2002), President and Chief Executive Officer of Constellation Energy (since November 2001); and Chairman of the Board of BGE (since July 2002)	Global Head of Investment Banking and Global Head of Private Banking Deutsche Banc Alex. Brown.
E. Follin Smith	46	Executive Vice President (since January 2004), Chief Financial Officer (since June 2001) and Chief Administrative Officer (since January 2004) of Constellation Energy; and Senior Vice President and Chief Financial Officer of Baltimore Gas and Electric Company (since January 2002)	Senior Vice President Constellation Energy; and Senior Vice President and Chief Financial Officer Armstrong Holdings, Inc.
Thomas V. Brooks	43	Chairman of Constellation Energy Commodities Group, Inc. (since August 2005); Vice Chairman (since August 2005) and Executive Vice President of Constellation Energy (since January 2004)	President Constellation Energy Commodities Group, Inc.; Executive Vice President Constellation Energy; Vice President of Business Development and Strategy Constellation Energy; and Vice President Goldman Sachs.
Michael J. Wallace	58	President of Constellation Generation Group, LLC (since January 2002); Executive Vice President of Constellation Energy (since January 2004)	Managing Director and Member Barrington Energy Partners.
Thomas F. Brady	56	Executive Vice President, Corporate Strategy and Retail Competitive Supply of Constellation Energy (since January 2004)	Senior Vice President, Corporate Strategy and Development Constellation Energy; and Vice President, Corporate Strategy and Development Constellation Energy.

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Irving B. Yoskowitz	60	Executive Vice President and General Counsel of Constellation Energy (since June 2005)	Senior Counsel Crowell & Moring (law firm); Senior Partner Global Technology Partners, LLC (investment banking and consulting firm); and Senior Advisor Akin Gump Strauss Hauer Feld LLP (law firm).
Felix J. Dawson	38	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.; Managing Director Constellation Energy Commodities Group, Inc.; Managing Director, Co-Head Origination Constellation Energy Commodities Group, Inc.; and Vice President Goldman Sachs Power, LLC.
George E. Persky	36	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.; Managing Director Constellation Energy Commodities Group, Inc.; Manager, Business Development and Strategy Constellation Energy; and Associate, Goldman Sachs.
Kenneth W. DeFontes, Jr.	55	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	54	Senior Vice President, Corporate Affairs of Constellation Energy (since January 2004)	Vice President, Corporate Affairs Constellation Energy; and Senior Vice President and Group Head Ogilvy Public Relations.
John R. Collins	48	Senior Vice President (since January 2004) and Chief Risk Officer of Constellation Energy (since December 2001)	Vice President Constellation Energy; Managing Director Finance Constellation Power Source Holdings, Inc.; and Managing Director and Senior Financial Officer Constellation Energy Commodities Group, Inc.
Beth S. Perlman	45	Senior Vice President (since January 2004) and Chief Information Officer of Constellation Energy (since April 2002)	Vice President, Technology Enron Corporation.
Marc L. Ugol	47	Senior Vice President, Human Resources of Constellation Energy (since January 2004)	Vice President, Human Resources Constellation Energy; and Senior Vice President, Human Resources and Administration Tellabs, Inc.

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

PART II

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

Stock Trading

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

As of January 31, 2006, there were 43,709 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 2006, we announced an increase in our quarterly dividend from $0.335 to $0.3775 per share payable April 3, 2006 to holders of record on March 10, 2006. This is equivalent to an annual rate of $1.51 per share.

Quarterly dividends were declared on our common stock during 2005 and 2004 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

	2005			2004		
		Price*			Price*	
	Dividend Declared	High	Low	Dividend Declared	High	Low
First Quarter	$ 0.335	$ 53.55	$ 43.01	$ 0.285	$ 41.47	$ 38.52
Second Quarter	0.335	57.91	50.36	0.285	41.35	35.89
Third Quarter	0.335	62.09	56.50	0.285	41.18	36.76
Fourth Quarter	0.335	62.60	50.40	0.285	44.90	39.90
Total	$ 1.340			$ 1.140		

* Based on New York Stock Exchange Composite Transactions.

Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents shares surrendered by employees to exercise stock options and to satisfy tax withholding obligations on vested restricted stock and stock option exercises.

Period	Total Number of Shares Purchased	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans and Programs
October 1 October 31, 2005	889	$ 55.88		
November 1 November 30, 2005	123	51.70		
December 1 December 31, 2005	1,982,414	58.33		
Total	1,983,426	$ 58.33		

Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2005	2004	2003	2002(1)	2001
		(In millions, except per share amounts)			
Summary of Operations					
Total Revenues	**$ 17,132.0**	$ 12,286.4	$ 9,454.1	$ 4,771.6	$ 3,683.0
Total Expenses	**16,073.9**	11,261.2	8,431.0	3,711.5	3,267.3
Income From Operations	**1,058.1**	1,025.2	1,023.1	1,060.1	415.7
Other Income	**62.8**	25.3	20.7	33.8	0.8
Fixed Charges	**310.1**	326.8	336.5	277.3	236.0
Income Before Income Taxes	**810.8**	723.7	707.3	816.6	180.5
Income Taxes	**204.1**	156.9	250.6	301.2	61.3
Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**606.7**	566.8	456.7	515.4	119.2
Income (Loss) from Discontinued Operations, Net of Income Taxes	**23.6**	(27.1)	19.0	10.2	(36.8)
Cumulative Effects of Changes in Accounting Principles, Net of Income Taxes	**(7.2)**		(198.4)		8.5
Net Income	**$ 623.1**	$ 539.7	$ 277.3	$ 525.6	$ 90.9
Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Assuming Dilution	**$ 3.38**	$ 3.28	$ 2.74	$ 3.14	$ 0.75
Income (Loss) from Discontinued Operations	**0.13**	(0.16)	0.11	0.06	(0.23)
Cumulative Effects of Changes in Accounting Principles	**(0.04)**		(1.19)		0.05
Earnings Per Common Share Assuming Dilution	**$ 3.47**	$ 3.12	$ 1.66	$ 3.20	$ 0.57
Dividends Declared Per Common Share	**$ 1.34**	$ 1.14	$ 1.04	$ 0.96	$ 0.48
Summary of Financial Condition					
Total Assets	**$ 21,473.9**	$ 17,347.1	$ 15,593.0	$ 14,943.3	$ 14,697.5
Short-Term Borrowings	**$ 0.7**	$	$ 9.6	$ 10.5	$ 975.0
Current Portion of Long-Term Debt	**$ 491.3**	$ 480.4	$ 343.2	$ 426.2	$ 1,406.7
Capitalization					
Long-Term Debt	**$ 4,369.3**	$ 4,813.2	$ 5,039.2	$ 4,613.9	$ 2,712.5

	2005	2004	2003	2002(1)	2001
Minority Interests	**22.4**	90.9	113.4	105.3	101.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**4,915.5**	4,726.9	4,140.5	3,862.3	3,843.6
Total Capitalization	**$ 9,497.2**	$ 9,821.0	$ 9,483.1	$ 8,771.5	$ 6,847.8
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**3.38**	3.02	2.90	3.31	1.39
Book Value Per Share of Common Stock	**$ 27.57**	$ 26.81	$ 24.68	$ 23.44	$ 23.48

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

(1) Total revenues for the year ended December 31, 2002 include $255.5 million of gains recognized on the sale of our outstanding shares of Orion Power Holdings, Inc.

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

	2005	2004	2003	2002	2001
			(In millions)		
Summary of Operations					
Total Revenues	**$ 3,009.3**	$ 2,724.7	$ 2,647.6	$ 2,547.3	$ 2,720.7
Total Expenses	**2,612.8**	2,353.3	2,262.6	2,181.0	2,408.9
Income From Operations	**396.5**	371.4	385.0	366.3	311.8
Other Income (Expense)	**5.9**	(6.4)	(5.4)	10.7	0.4
Fixed Charges	**93.5**	96.2	111.2	140.6	154.6
Income Before Income Taxes	**308.9**	268.8	268.4	236.4	157.6
Income Taxes	**119.9**	102.5	105.2	93.3	60.3
Net Income	**189.0**	166.3	163.2	143.1	97.3
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Earnings Applicable to Common Stock	**$ 175.8**	$ 153.1	$ 150.0	$ 129.9	$ 84.1
Summary of Financial Condition					
Total Assets	**$ 4,742.1**	$ 4,662.9	$ 4,706.6	$ 4,779.9	$ 4,954.5
Current Portion of Long-Term Debt	**$ 469.6**	$ 165.9	$ 330.6	$ 420.7	$ 666.3
Capitalization					
Long-Term Debt	**$ 1,015.1**	$ 1,359.5	$ 1,343.7	$ 1,499.1	$ 1,821.7
Minority Interest	**18.3**	18.7	18.9	19.4	5.0
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**1,622.5**	1,566.0	1,487.7	1,461.7	1,131.4
Total Capitalization	**$ 2,845.9**	$ 3,134.2	$ 3,040.3	$ 3,170.2	$ 3,148.1
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**4.22**	3.75	3.36	2.66	1.99
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**3.45**	3.08	2.82	2.31	1.75

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 2005, 2004, and 2003. 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.

Pending Merger with FPL Group, Inc.

In order to further our strategies discussed below, we entered into an Agreement and Plan of Merger with FPL Group, Inc. (FPL Group). We discuss our pending merger with FPL Group in more detail in *Note 15*.

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, industrial customers, and commercial customers.

We obtain this energy through both owned and contracted supply resources. Our generation fleet is strategically located in deregulated markets across the country and is diversified by fuel type, including nuclear, coal, gas, oil, and renewable sources. In addition to owning generating facilities, we contract for power from other merchant providers, typically through power purchase agreements. We intend to remain diversified between regulated transmission and distribution and competitive supply. We will use both our owned generation and our contracted generation to support our competitive supply operations.

We are a leading national competitive supplier of energy. In 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.

As part of our risk management 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.

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

Collectively, the integration of owned and contracted electric generation assets with origination, fuel procurement, and risk management expertise, allows our merchant energy business to earn incremental margin and more effectively manage energy and commodity price risk over geographic regions and over time. Our focus is on providing solutions to customers' energy needs, and our wholesale marketing and risk management operation adds value to our owned and contracted generation assets by providing national market access, market infrastructure, real-time market intelligence, risk management and arbitrage opportunities, and transmission and transportation expertise. Generation capacity supports our wholesale marketing and risk management operation by providing a source of reliable power supply.

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

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

We are constantly reevaluating our strategies and might consider:

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

Business Environment

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 electricity markets. The pace of deregulation in these states varies based on historical moves to competition and responses to recent market events. While many states continue to support 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.

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 Electric Regulatory Matters and Competition* section.

Regulation by the Maryland PSC

In addition to electric restructuring, which is discussed in *Item 1. Business Electric Regulatory Matters and Competition* section, regulation by the Maryland Public Service Commission (Maryland PSC) significantly influences BGE's businesses. The Maryland PSC determines the rates that BGE can charge customers 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), competitive transition charges (CTC), electric supply (commodity charge), transmission, a universal service surcharge, and certain taxes. The rates for BGE's regulated gas business continue to consist of a delivery charge (base rate) and a commodity charge.

Base Rates

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. 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.

As a result of the deregulation of electric generation in Maryland, BGE's residential electric base rates are frozen until July 2006. Electric base rates were frozen until July 2004 for commercial and industrial customers. In early 2006, the Maryland PSC commenced a proceeding, and legislation was introduced in the Maryland General Assembly, to consider methods for requiring BGE to defer recovery of some of its costs of providing residential POLR service. These actions are a result of the anticipated increase in POLR prices expected to take place upon the expiration of the residential rate freeze in June 2006. Any decision by the Maryland PSC or legislation adopted by the Maryland General Assembly, that would defer recovery of, or would not allow BGE to fully recover its costs could have a material impact on our, and BGE's, financial results and liquidity. We discuss electric deregulation in *Item 1. Business Electric Regulatory Matters and Competition* section.

In April 2005, BGE filed an application for a $52.7 million annual increase in its gas base rates. The Maryland PSC issued an order in December 2005 granting BGE an annual increase of $35.6 million. Certain parties to the proceeding have sought judicial review and Maryland PSC rehearing of the decision. BGE will not seek review of any aspect of the order. We cannot provide assurance that a court will not reverse any aspect of the order or that it will not remand certain issues to the Maryland PSC.

Electric Commodity and Transmission Charges

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

Gas Commodity Charge

BGE charges its gas customers separately for the natural gas they purchase. The price BGE charges for the natural gas is based on a market-based rates incentive mechanism approved by the Maryland PSC. We discuss market-based rates in more detail in the *Regulated Gas Business Gas Cost Adjustments* section and in *Note 6.*

Federal Regulation

FERC

The FERC has jurisdiction over various aspects of our business, including transmission and wholesale electricity sales. We believe that FERC's continued commitment to competition in wholesale energy markets should result in improved 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 and other regulatory bodies. We cannot predict the outcome of such a review at this time. However, changes to the structure of these markets could have a material effect on our financial results.

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

In November 2004, FERC eliminated through and out transmission rates between the Midwest Independent System Operators (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 are in effect from December 1, 2004 through March 31, 2006. FERC has 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.

In addition, FERC has indicated that it will provide transmission customers that are charged the SECA rates with an opportunity to demonstrate that such charges should be shifted to their wholesale power suppliers. We are a recipient of SECA payments, payer of SECA charges, and supplier to whom such charges may be shifted. We are unable to predict the timing or 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 May 2005, FERC issued an order accepting BGE's joint application to have network transmission rates established through a formula that tracks costs instead of through fixed rates. The formula approach became effective June 1, 2005, and the implementation of these rates did not have a material effect on our, or BGE's, financial results. The use of this formula approach is subject to refund based on the outcome of a hearing before an administrative law judge. The hearing process has been suspended while the various parties discuss a possible settlement. We cannot predict the outcome of this proceeding or whether FERC will ultimately affirm either a settlement or the judge's decision.

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

Federal Energy Legislation

The Energy Policy Act of 2005 (EPACT 2005) was signed by the President on August 8, 2005. The legislation encourages investments in energy production and delivery infrastructure, including further development of competitive wholesale energy markets, and promotes the use of a diverse mix of fuels and renewable technologies to generate electricity, including federal support and tax incentives for clean coal, nuclear, and renewable power generation. Effective February 2006, the legislation repealed the Public Utility Holding Company Act of 1935 (PUHCA 1935).

In addition, there are a number of FERC rulemaking proceedings that relate to the implementation of EPACT 2005 including proceedings relating to FERC's new responsibilities following the repeal of PUHCA 1935, its revised merger authority, its new authority over electric grid reliability, and its new authority with respect to addressing electric and gas market manipulation. While FERC has moved expeditiously to implement its new authority under EPACT 2005, at this time we are unable to predict the ultimate impact of these rules or the possible effect on our business or financial results given that these rules may be subject to further revision or clarification as a result of requests for rehearing or court appeals but they could have a material impact on our financial results.

There are also rulemakings required from other federal agencies, the outcome of which could affect our financial results, but we cannot at this time predict such outcome or the actual effect on our financial results.

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 allows BGE to record a monthly adjustment to our regulated gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the *Regulated Gas Business Weather Normalization* section.

Other Factors

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

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

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

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

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

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

Environmental Matters and Legal Proceedings

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

Accounting Standards Adopted and Issued

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

Critical Accounting Policies

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

- our reported amounts of revenues and expenses in our Consolidated Statements of Income,
- our reported amounts of assets and liabilities in our Consolidated Balance Sheets, and
- our disclosure of contingent assets and liabilities.

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

Management believes the following accounting policies represent critical accounting policies as defined by the Securities and Exchange Commission (SEC). The SEC defines critical accounting policies as those that are both most important to the portrayal of a company's financial condition and results of operations and require management's most difficult, subjective, or complex judgment, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods. We discuss our significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in *Note 1*.

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 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.

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 contracts that do not meet these criteria, we may also analyze whether they qualify for hedge accounting, including performing an evaluation of historical 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 record the fair value of derivatives for which we have elected hedge accounting in "Risk management assets and liabilities."

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

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

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

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

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

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

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

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

our ability to designate and qualify derivative contracts for normal purchase and sale accounting or hedge accounting under SFAS No. 133,

potential volatility in earnings from ineffectiveness associated with derivatives subject to hedge accounting,

potential volatility in earnings from derivative contracts that serve as economic hedges but do not meet the accounting requirements to qualify for normal purchase and 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 legislation or in the business climate,
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,
- a current-period loss combined with a history of losses or the projection of future losses, or
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

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

In order to estimate an asset's future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). If we are considering alternative courses of action to recover the carrying amount of a long-lived asset (such as the potential sale of an asset), we probability-weight the alternative courses of action to estimate the cash flows.

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

For long-lived assets that can be classified as assets held for sale under SFAS No. 144, an impairment loss is recognized to the extent their carrying amount exceeds their fair value less costs to sell.

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

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

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

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 Position 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 requires us to determine whether a decline in fair value of an investment below the amortized cost basis is other than temporary. If we determine that the decline in fair value is judged to be other than temporary, the cost basis of the investment must be written down to fair value as a new cost basis.

Goodwill

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

Asset Retirement Obligations

We incur legal obligations associated with the retirement of certain long-lived assets. SFAS No. 143, *Accounting for Asset Retirement Obligations,* provides the accounting for legal obligations associated with the retirement of long-lived assets. We incur such legal obligations as a result of environmental and other government regulations, contractual agreements, and other factors. The application of this standard requires significant judgment due to the large number and diverse nature of the assets in our various businesses and the estimation of future cash flows required to measure legal obligations associated with the retirement of specific assets. 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 very long time horizons involved, the actual obligation could vary from the assumptions used in our estimates, and the impact of such variations could be material.

Significant Events

Pending Merger with FPL Group, Inc.

On December 18, 2005, Constellation Energy entered into an Agreement and Plan of Merger with FPL Group, Inc. We discuss the details of this pending merger in *Note 15*.

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

Commodity Prices

During 2005, the energy markets were affected by higher commodity prices caused by a tight supply and demand balance, the impact of hot weather, and hurricane-related supply disruptions in the Gulf Coast. These events contributed to the following changes in our financial statements:

- total mark-to-market assets increased $1,501.4 million and total mark-to-market liabilities increased $1,386.3 million since December 31, 2004,
- total risk management assets increased $1,092.6 million and total risk management liabilities increased $742.5 million since December 31, 2004,
- customer deposits and collateral increased $235.1 million since December 31, 2004,
- accumulated other comprehensive income decreased $314.0 million since December 31, 2004,
- total revenues increased $4,845.6 million during 2005 compared to 2004, and
- total fuel and purchased energy expenses increased $4,546.8 million during 2005 compared to the same period of 2004.

We discuss the impact of higher commodity prices on our financial condition and results of operations in more detail in the following sections:

- *Merchant Energy Results*,

Financial Condition,

Contractual Payment Obligations and Committed Amounts, and

Market Risk.

Discontinued Operations

In June 2005, we sold our Oleander generating facility and in October 2005, we sold Constellation Power International Investments, Ltd., which held our other nonregulated international investments. Our other nonregulated international investments included our interests in a Panamanian electric distribution facility and a fund that holds interests in two South American energy projects.

We discuss the sale of the Oleander generating facility and our other nonregulated international investments in more detail in the *Note 2*.

Business Combination and Asset Acquisition

In April 2005, we acquired Cogenex Corporation and in June 2005, we acquired working interests in gas producing fields in Texas and Alabama.

We discuss these transactions in more detail in *Note 15*.

Dividend Increase

In January 2006, we announced an increase in our quarterly dividend to $0.3775 per share on our common stock. This is equivalent to an annual rate of $1.51 per share. Previously, our quarterly dividend on our common stock was $0.335 per share, equivalent to an annual rate of $1.34 per share.

Results of Operations

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments. Significant changes in other income and expense, fixed charges, and income taxes are discussed in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section.

Overview

Results

	2005	2004	2003
		(In millions, after-tax)	
Merchant energy	**$ 430.2**	$ 426.4	$ 301.1
Regulated electric	**149.4**	131.1	107.5
Regulated gas	**26.7**	22.2	43.0
Other nonregulated	**0.4**	(12.9)	5.1
Income from continuing operations and before cumulative effects of changes in accounting principles	**606.7**	566.8	456.7
Income (loss) from discontinued operations	**23.6**	(27.1)	19.0
Cumulative effects of changes in accounting principles	**(7.2)**		(198.4)
Net Income	**$ 623.1**	$ 539.7	$ 277.3
Other Items Included in Operations:			
Non-qualifying hedges	**$ (24.9)**	$ 0.2	$ (28.7)
Merger-related transaction costs	**(15.6)**		
Workforce reduction costs	**(2.6)**	(5.9)	(1.3)
Recognition of 2003 synthetic fuel tax credits		35.9	
Total Other Items	**$ (43.1)**	$ 30.2	$ (30.0)

2005

Our total net income for 2005 increased $83.4 million, or $0.35 per share, compared to the same period of 2004 mostly because of the following:

We had higher earnings of approximately $58 million at our wholesale marketing and risk management operation. This increase is primarily due to the realization of higher gross margin, which included the termination or restructuring of several energy contracts and higher mark-to-market results in earnings. We discuss these terminations, restructurings, and mark-to-market results in more detail in the *Competitive Supply* section. This increase in earnings was partially offset by higher load-serving costs resulting from extreme weather and volatile commodity prices and higher operating expenses.

We recorded higher income from discontinued operations of $50.7 million after-tax. In 2005, we recorded in "Income (loss) from discontinued operations" earnings of $23.6 million related to the sale of our Oleander generating facility and our other nonregulated international investments. In 2004, we recorded in "Income (loss) from discontinued operations" a loss of $49.1 million after tax related to the sale of our Hawaiian geothermal facility which had a negative impact in that period. The loss was offset by the reclassification of earnings of $22.0 million after-tax from our Oleander and international operations to "Income (loss) from discontinued operations." We discuss the sale of these operations in more detail in *Note 2.*

We had higher earnings of $32.7 million after-tax primarily due to higher interest and investment income due to a higher cash balance, and higher decommissioning trust asset earnings, and lower interest expense resulting from the maturity of $300.0 million in long-term debt in 2005 and the favorable impact of floating-rate swaps.

We had higher earnings of $29.1 million after-tax at our Nine Mile Point and Ginna facilities primarily due to productivity improvements and cost saving initiatives partially offset by inflationary cost increases and costs associated with the planned refueling outage at Ginna.

We had higher earnings of $22.8 million after-tax at our regulated businesses primarily due to favorable weather during 2005 compared to 2004.

We had higher earnings of approximately $17 million after-tax due to the absence of coal delivery issues that were experienced in 2004 that had a negative impact in that period. We discuss the coal delivery issues in more detail in the *Business Environment Other Factors* section.

We had higher earnings from our other nonregulated businesses of $13.3 million after-tax, including higher gains from the continued liquidation of our non-core investments and the results of Cogenex, which was acquired in April 2005. We discuss the acquisition of Cogenex in more detail in *Note 15*.

We had higher earnings at our South Carolina synthetic fuel facility of $7.6 million after-tax due to a higher level of production in 2005 compared to 2004.

These increases were partially offset by the following:

Our merchant energy business recognized $35.9 million of 2003 synthetic fuel tax credits in 2004 which had a positive impact in that period.

We had lower earnings at our retail competitive supply operation of $25.1 million after-tax primarily due to higher costs to serve our load obligations in Texas and the absence of bankruptcy settlements that had a favorable impact in 2004.

We had lower earnings of $25.1 million after-tax related to losses associated with certain economic hedges that do not qualify for cash-flow hedge accounting treatment. We discuss these economic hedges in more detail in the *Mark-to-Market* section.

We had lower earnings of $15.6 million after-tax due to external costs associated with the execution of our merger agreement with FPL Group.

We had lower earnings of $20.0 million after-tax due to lower CTC revenues at our merchant energy business.

We had lower earnings of $8.5 million after-tax related to the impact of expensing stock options during the fourth quarter of 2005.

We had lower earnings of $7.2 million after-tax due to the cumulative effect of adopting FIN 47 and SFAS No. 123 Revised (SFAS No. 123R), *Share-Based Payment*. We discuss the adoption of these standards in detail in *Note 1*.

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

2004

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

In 2003, we recorded a $266.1 million after-tax loss for the cumulative effect of adopting Emerging Issues Task Force (EITF) Issue 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*. This was partially offset by a $67.7 million after-tax gain for the cumulative effect of adopting SFAS No. 143. These items had a combined negative impact during 2003.

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

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

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

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

We had higher earnings due to lower after-tax losses of $28.9 million associated with certain economic hedges that do not qualify for cash-flow hedge accounting treatment. We discuss these economic hedges in more detail in the *Mark-to-Market* section.

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

These increases were partially offset by the following:

We recorded a $49.1 million after-tax, loss from discontinued operations on the sale of our Hawaiian geothermal facility.

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

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

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

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

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 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 wholesale marketing and risk management operation actively uses energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. As part of our risk management activities we trade energy and energy-related commodities 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

	2005	2004	2003
		(In millions)	
Revenues	**$ 14,786.1**	$ 10,347.5	$ 7,587.5
Fuel and purchased energy expenses	**(12,308.9)**	(8,124.8)	(5,702.2)
Operating expenses	**(1,364.3)**	(1,172.8)	(932.8)
Merger-related transaction costs	**(11.2)**		
Workforce reduction costs	**(4.4)**	(9.7)	(1.2)
Depreciation, depletion, and amortization	**(269.6)**	(239.2)	(214.6)
Accretion of asset retirement obligations	**(62.1)**	(53.2)	(42.7)
Taxes other than income taxes	**(112.2)**	(88.5)	(85.9)
Income from Operations	**$ 653.4**	$ 659.3	$ 608.1
Income from continuing operations and before cumulative effects of changes in accounting principles (after-tax)	**$ 430.2**	$ 426.4	$ 301.1
Income (loss) from discontinued operations (after-tax)	**3.0**	(36.5)	11.9
Cumulative effects of changes in accounting principles (after-tax)	**(7.4)**		(198.4)
Net Income	**$ 425.8**	$ 389.9	$ 114.6
Other Items Included in Operations (after-tax)			
Non-qualifying hedges	**$ (24.9)**	$ 0.2	$ (28.7)
Merger-related transaction costs	**(10.4)**		
Workforce reduction costs	**(2.6)**	(5.9)	(0.7)
Recognition of 2003 synthetic fuel tax credits		35.9	
Total Other Items	**$ (37.9)**	$ 30.2	$ (29.4)

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

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

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

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

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

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

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

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

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

	2005		2004		2003	
			(Dollar amounts in millions)			
Revenues:						
Mid-Atlantic Region	**$ 2,283.9**		$ 1,925.6		$ 1,696.2	
Plants with Power Purchase Agreements	**829.6**		714.5		574.6	
Competitive Supply						
Retail	**6,942.3**		4,280.0		2,567.7	
Wholesale	**4,672.3**		3,353.8		2,703.9	
Other	**58.0**		73.6		45.1	
Total	**$ 14,786.1**		$ 10,347.5		$ 7,587.5	
Fuel and purchased energy expenses:						
Mid-Atlantic Region	**$ (1,436.5)**		$ (946.9)		$ (711.6)	
Plants with Power Purchase Agreements	**(79.6)**		(53.1)		(48.0)	
Competitive Supply						
Retail	**(6,668.2)**		(4,011.4)		(2,389.5)	
Wholesale	**(4,124.6)**		(3,113.4)		(2,553.1)	
Other						
Total	**$ (12,308.9)**		$ (8,124.8)		$ (5,702.2)	
Gross margin:		**% of Total**		**% of Total**		**% of Total**
Mid-Atlantic Region	**$ 847.4**	**34%**	$ 978.7	44%	$ 984.6	52%
Plants with Power Purchase Agreements	**750.0**	**30**	661.4	30	526.6	28
Competitive Supply						
Retail	**274.1**	**11**	268.6	12	178.2	9
Wholesale	**547.7**	**22**	240.4	11	150.8	8
Other	**58.0**	**3**	73.6	3	45.1	3

	2005		2004		2003	
Total	**$ 2,477.2**	**100%**	$ 2,222.7	100%	$ 1,885.3	100%

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

Mid-Atlantic Region

	2005	2004	2003
		(In millions)	
Revenues	**$ 2,283.9**	$ 1,925.6	$ 1,696.2
Fuel and purchased energy expenses	**(1,436.5)**	(946.9)	(711.6)
Gross margin	**$ 847.4**	$ 978.7	$ 984.6

The decrease in Mid-Atlantic Region gross margin in 2005 compared to 2004 is primarily due to rising commodity prices and hotter than normal weather during the third quarter of 2005, which resulted in higher load-serving costs. In addition, CTC revenues were $33.1 million lower during 2005 compared to the same period of 2004. These decreases in gross margin were partially offset by the absence of coal delivery issues that we experienced in 2004 that had a negative impact in that period. We discuss the coal delivery issues in the *Business Environment Other Factors* section.

CTC revenues will continue to decrease as residential, commercial, and industrial customers complete their CTC obligation. CTC revenues will be completely phased-out for residential customers by June 30, 2006 and CTC revenues for commercial and industrial customers will begin to be phased-out after June 30, 2006. We discuss the change in CTC revenue over time in more detail in *Item 1. Business*.

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

Plants with Power Purchase Agreements

	2005	2004	2003
		(In millions)	
Revenues	**$ 829.6**	$ 714.5	$ 574.6
Fuel and purchased energy expenses	**(79.6)**	(53.1)	(48.0)
Gross margin	**$ 750.0**	$ 661.4	$ 526.6

The increase in gross margin from our Plants with Power Purchase Agreements in 2005 compared to 2004 was primarily due to:

- higher gross margin of $71.5 million from Ginna, which was acquired in June 2004. This increase in gross margin at Ginna includes an increase in revenues of $76.9 million. We discuss this acquisition in more detail in *Note 15,* and
- higher gross margin of $39.0 million at our Nine Mile Point facility that benefited from higher generation primarily due to fewer refueling outage days, the absence of an unplanned outage that occurred in January 2004, and higher prices on the portion of our output sold into the wholesale market.

These increases in gross margin were partially offset by $21.9 million primarily related to changes in commodity prices that had a negative impact on realized hedging activities related to the portion of these facilities sold into the wholesale market.

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

- gross margin of $112.4 million from Ginna. The increase in gross margin includes higher revenues of $119.1 million, and
- higher gross margin of $45.9 million from the High Desert facility that contributed a full year of gross margin in 2004 compared to eight months in 2003.

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

Competitive Supply

Retail

	2005	2004	2003
		(In millions)	
Accrual revenues	**$ 6,944.2**	$ 4,281.0	$ 2,567.7
Mark-to-market results recorded in earnings	**18.3**	(1.0)	
Fuel and purchased energy expenses	**(6,688.4)**	(4,011.4)	(2,389.5)
Gross margin	**$ 274.1**	$ 268.6	$ 178.2

The slight increase in gross margin from our retail competitive supply activities in 2005 compared to 2004 is primarily due to serving approximately 20 million more megawatt hours in 2005 compared to 2004 mostly due to the growth of this operation and the positive impact of certain contracts that were recorded as mark-to-market. These increases were substantially offset by:

a combination of higher market prices for electricity, price volatility, and increased customer usage primarily in Texas, which increased our cost to serve our load-serving obligations.

the expiration of higher margin contracts, and

the absence of favorable bankruptcy settlements, which had a positive impact in 2004. We discuss the favorable bankruptcy settlements below.

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

serving approximately 16 million more megawatt hours partially offset by lower realized margins due to increased wholesale power costs in 2004 compared to 2003,

a bankruptcy settlement from PG&E of $10.3 million in 2004, and a favorable settlement of a pre-acquisition liability of $6.6 million also related to a bankruptcy proceeding in 2004, and

lower contract amortization, which reduced margin by $9.2 million, relating to the fair value of contracts acquired.

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

Wholesale

	2005	2004	2003
		(In millions)	
Accrual revenues	**$ 4,281.8**	$ 3,253.7	$ 2,667.7
Fuel and purchased energy expenses	**(4,124.6)**	(3,113.4)	(2,553.1)
Wholesale accrual activities	**157.2**	140.3	114.6
Mark-to-market results recorded in earnings	**390.5**	100.1	36.2
Gross margin	**$ 547.7**	$ 240.4	$ 150.8

We analyze our wholesale accrual and mark-to-market competitive supply activities separately on the next page.

Wholesale Accrual Activities

Our wholesale marketing and risk management operation's accrual gross margin was $16.9 million higher in 2005 compared to 2004 primarily due to newly originated and realized business in power, gas, and coal in 2005, including several contract terminations and restructurings. During 2005, we terminated or restructured several in-the-money contracts in exchange for upfront cash payments and a reduction or cancellation of future performance obligations. The termination or restructuring of two contracts allowed us to lower our exposure to performance risk under these contracts, and resulted in the realization of $77.0 million of pre-tax earnings in 2005 that would have been recognized over the life of these contracts. These increases were partially offset by lower gross margins of approximately $60 million mostly due to the absence of several favorable items, including settlements, power prices, and contracts that had a positive impact in 2004.

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

Mark-to-Market

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

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

Mark-to-market results recorded in earnings were as follows:

	2005	2004	2003
		(In millions)	
Unrealized mark-to-market results recorded in earnings			
Origination gains	**$ 61.6**	$ 19.7	$ 62.3
Risk management and trading			
Unrealized changes in fair value	**347.2**	79.4	(26.1)
Changes in valuation techniques			
Reclassification of settled contracts to realized	**(257.7)**	(85.4)	(123.5)
Total risk management and trading	**89.5**	(6.0)	(149.6)
Total unrealized mark-to-market*	**151.1**	13.7	(87.3)
Realized mark-to-market	**257.7**	85.4	123.5
Total mark-to-market results recorded in earnings	**$ 408.8**	$ 99.1	$ 36.2

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

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

- 6 transactions completed in 2005, one of which contributed approximately $35 million pre-tax,
- 7 transactions completed in 2004, of which no transaction contributed in excess of $10 million pre-tax, and
- 14 transactions completed in 2003, of which one transaction contributed approximately $10 million pre-tax.

As noted above, the recognition of origination gains is dependent on sufficient observable market data. Liquidity and market conditions impact our ability to identify sufficient, objective market-price information to permit recognition of origination gains. As a result, while our strategy and competitive position provide the opportunity to continue to originate such transactions, the level of origination 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.

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

Mark-to-market results recorded in earnings increased $309.7 million in 2005 compared to 2004 due to:

- approximately $260 million primarily related to a higher level of risk management and trading activities. Increases in our gas and coal activities, higher commodity price volatility, and greater market liquidity resulted in more opportunities to deploy risk capital and to earn additional returns in 2005 compared to 2004. These items resulted in an increased number of transactions that were entered into and realized during 2005 and a higher level of open positions that resulted in increased gains in 2005 compared to 2004. During 2005, slightly more than half of the mark-to-market results were derived from power, approximately one-third from gas, and the remainder from other transactions.
- $41.9 million related to a higher level of origination gains as discussed on the previous page, and
- $49.9 million related to the decrease in the close-out adjustment during 2005 compared to the prior year for transactions that we have now observed sufficient market price information and/or we realized cash flows since the transactions' inception.

These increases in mark-to-market results recorded in earnings were partially offset by the impact of $41.5 million of higher mark-to-market losses on certain economic hedges that did not qualify for cash-flow hedge accounting treatment. We discuss these economic hedges in more detail below.

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

Changing forward prices result in shifting value between accrual contracts and the associated mark-to-market positions of certain contracts in New England that contain fuel adjustment clauses and gas transportation contract hedges, producing a timing difference in the recognition of earnings on these transactions. These mark-to-market hedges are economically effective; however, they do not qualify for cash-flow hedge accounting under SFAS No. 133. As a result, we recorded $41.2 million of pre-tax losses in 2005, $0.3 million of pre-tax gains in 2004, and pre-tax losses of $47.4 million in 2003. These mark-to-market gains and losses will be offset as we realize the related accrual load-serving positions in cash.

Mark-to-Market Energy Assets and Liabilities

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

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

At December 31,		**2005**		**2004**
		(In millions)		
Current Assets	**$**	**1,339.2**	$	567.3
Noncurrent Assets		**1,089.3**		359.8
Total Assets		**2,428.5**		927.1
Current Liabilities		**1,348.7**		559.7
Noncurrent Liabilities		**912.3**		315.0
Total Liabilities		**2,261.0**		874.7
Net mark-to-market energy asset	**$**	**167.5**	$	52.4

The following are the primary sources of the change in net mark-to-market energy asset during 2005 and 2004:

	2005	2004
	(In millions)	
Fair value beginning of year	**$ 52.4**	$ 18.8
Changes in fair value recorded in earnings		
Origination gains	**$ 61.6**	$ 19.7
Unrealized changes in fair value	**347.2**	79.4
Changes in valuation techniques		
Reclassification of settled contracts to realized	**(257.7)**	(85.4)
Total changes in fair value recorded in earnings	**151.1**	13.7
Contracts acquired	**17.4**	
Changes in value of exchange-listed futures and options	**(119.9)**	(15.8)
Net change in premiums on options	**79.7**	29.4
Other changes in fair value	**(13.2)**	6.3
Fair value at end of year	**$ 167.5**	$ 52.4

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

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

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

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

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

The net mark-to-market energy asset also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income:

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

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

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

The settlement terms of our net mark-to-market energy asset and sources of fair value as of December 31, 2005 are as follows:

	Settlement Term							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Fair Value**
				(In millions)				
Prices provided by external sources (1)	$ (12.6)	$ 63.5	$ 81.8	$ (2.7)	$ (2.1)	$	$	$ 127.9
Prices based on models	3.1	4.7	10.2	(0.6)	17.5	1.4	3.3	39.6
Total net mark-to-market energy asset	$ (9.5)	$ 68.2	$ 92.0	$ (3.3)	$ 15.4	$ 1.4	$ 3.3	$ 167.5

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

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

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

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

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

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

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

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

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

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

Consistent with our risk management practices, the amounts shown in the table on the previous page as being valued using prices from external sources include the portion of long-term contracts for which we can obtain reliable prices from external sources. The remaining portions of these long-term contracts are shown in the table as being valued using models. In order to realize the entire value of a long-term contract in a single transaction, we would need to sell or assign the entire contract. If we were to sell or assign any of our long-term contracts in their entirety, we may not realize the entire value reflected in the table. However, based upon the nature of the wholesale marketing and risk management operation, we expect to realize the value of these contracts, as well as any contracts we may enter into in the future to manage our risk, over time as the contracts and related hedges settle in accordance with their terms. 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, 2005 and could change significantly as a result of future changes in these factors. Additionally, because the depth and liquidity of the power markets vary substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed.

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

Risk Management Assets and Liabilities

We record derivatives that qualify for designation as hedges under SFAS No. 133 in "Risk management assets and liabilities" in our Consolidated Balance Sheets. Our risk management assets and liabilities consisted of the following:

At December 31,	**2005**	**2004**
	(In millions)	
Current Assets	**$ 1,244.3**	$ 471.5
Noncurrent Assets	**626.0**	306.2
Total Assets	**1,870.3**	777.7

At December 31,		2005		2004
Current Liabilities		**483.5**		304.3
Noncurrent Liabilities		**1,035.5**		472.2
Total Liabilities		**1,519.0**		776.5
Net risk management asset	**$**	**351.3**	$	1.2

The significant increases in our gross risk management assets and liabilities were due primarily to higher commodity prices during 2005. These price increases resulted in larger positions with individual counterparties which must be recorded gross in our balance sheet unless a legal right of offset exists. The significant increase in our net risk management asset was due primarily to a contract that was previously designated as a cash-flow hedge that we elected to de-designate and to which the normal purchase and normal sales election was applied. At the point of de-designation, the fair value of the contract that was previously recorded in "Risk management liabilities" was reclassified to "Unamortized energy contract liabilities." These increases in our net risk management asset were partially offset by the assumption of below-market power sale agreements in connection with a customer contract restructuring. We discuss the de-designation of the cash-flow hedge in more detail on the next page. We discuss the customer contract restructuring transaction in more detail in *Note 4*.

Unamortized Energy Contract Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balance of nonderivative energy contracts that we acquired or derivatives designated as normal purchases and normal sales that we had previously recorded as "Mark-to-market energy assets and liabilities" or "Risk management assets and liabilities." Our unamortized energy contract assets and liabilities consisted of the following:

At December 31,	2005	2004
	(In millions)	
Current Assets	**$ 55.6**	$ 37.2
Noncurrent Assets	**141.2**	80.1
Total Assets	**$ 196.8**	$ 117.3
Current Liabilities	**$ 489.5**	$ 67.2
Noncurrent Liabilities	**1,118.7**	86.2
Total Liabilities	**$ 1,608.2**	$ 153.4

During 2005, we acquired several pre-existing nonderivative contracts that had been originated by other parties in prior periods when market prices were lower than current levels. Upon acquisition, we received approximately $530 million in cash and other consideration and recorded a liability in "Unamortized energy contracts." In addition, during 2005, we designated as normal purchases and normal sales contracts that we had previously recorded as cash-flow hedges in "Risk management liabilities." This change in designation resulted in a reclassification of $888.5 million from "Risk management liabilities" to "Unamortized energy contracts." Since the original forecasted transaction is still probable of occurring, the amount recorded in "Accumulated other comprehensive income" upon de-designation of the hedged position will remain and be amortized along with the unamortized energy contract liability. The de-designation and reclassification had no impact on our earnings.

Other

	2005	2004	2003
		(In millions)	
Revenues	**$ 58.0**	$ 73.6	$ 45.1

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. Earnings from our investments were $3.6 million in 2005, $18.0 million in 2004, and $2.1 million in 2003.

Other revenues decreased $15.6 million in 2005 compared to 2004 mostly due to an increased incentive fee and a deferred contingent transaction fee received from our synthetic fuel facilities located in Virginia and West Virginia that had a favorable impact in 2004.

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

At December 31, 2005, our investment in qualifying facilities and domestic power projects consisted of the following:

Book Value at December 31,	2005	2004
	(In millions)	
Project Type		
Coal	**$ 127.8**	$ 128.7
Hydroelectric	**55.9**	55.8

Book Value at December 31,		2005		2004
Geothermal		**43.7**		46.3
Biomass		**48.0**		50.2
Fuel Processing		**23.8**		22.5
Solar		**7.0**		10.4
Total	**$**	**306.2**	$	313.9

We believe the current market conditions for our equity-method investments that own geothermal, coal, hydroelectric, and fuel processing projects provide sufficient positive cash flows to recover our investments. We continuously monitor issues that potentially could impact future profitability of these investments, including environmental and legislative initiatives. We discuss certain risks and uncertainties in more detail in our *Forward Looking Statements* 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.

The ability to recover our costs in our equity-method investments that own biomass and solar projects is partially dependent upon subsidies from the State of California. Under the California Public Utility Act, subsidies currently exist in that the California Public Utilities Commission (CPUC) requires load-serving entities to identify a separate rate component to be collected from customers to fund the development of renewable resources technologies, including solar, biomass, and wind facilities. In addition, legislation in California requires that each load-serving entity increase its total procurement of eligible renewable energy resources by at least one percent per year so that 20% of its retail sales are procured from eligible renewable energy resources by 2017. The CPUC accelerated the deadline for compliance to 2010. The legislation also requires the California Energy Commission to award supplemental energy payments to load-serving entities to cover above-market costs of renewable energy.

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

Operating Expenses

Our merchant energy business operating expenses increased $191.5 million in 2005 compared to 2004 mostly due to the following:

- an increase of $101.8 million at our wholesale marketing and risk management operation due to an increase in compensation and benefit costs including our expanding gas and coal operations,
- an increase of $81.5 million from Ginna, which was acquired in June 2004,
- an increase of $26.5 million at our retail operation primarily related to a $10.8 million increase in uncollectible expenses and a $8.7 million increase in aggregator fees,
- an increase of $13.9 million at our gas-fired generating facilities primarily due to increased corporate overhead expenses, and
- an increase of $13.0 million at Calvert Cliffs primarily due to an increase in corporate overhead expenses, partially offset by fewer employees and a shorter refueling outage in 2005.

These increases in expense were partially offset by lower operating expenses of $56.5 million at Nine Mile Point primarily due to lower refueling outage expenses and a lower number of employees and contractors.

Our merchant energy business operating expenses increased $240.0 million in 2004 compared to 2003 mostly due to the following:

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

Merger-Related Transaction Costs

We discuss our pending merger with FPL Group and related costs as discussed in more detail in *Note 15*.

Workforce Reduction Costs

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

Depreciation, Depletion, and Amortization Expense

Merchant energy depreciation, depletion, and amortization expenses increased $30.4 million in 2005 compared to 2004 mostly due to:

- $10.2 million related to our South Carolina synthetic fuel facility,

- $8.8 million related to Ginna, which was acquired in June 2004, and
- $6.0 million increase related to our 2005 investments in gas producing facilities.

Merchant energy depreciation and amortization expense increased $24.6 million in 2004 compared to 2003 mostly due to:

- $10.3 million related to Ginna,
- $6.9 million related to our High Desert facility, which commenced operations in 2003, and
- $5.1 million related to our South Carolina synthetic fuel facility, which was acquired in May 2003.

Accretion of Asset Retirement Obligations

The increase in accretion expense of $8.9 million in 2005 compared to 2004 and $10.5 million in 2004 compared to 2003 is primarily due to Ginna which was acquired in June 2004 and the impact of normal compounding.

Taxes Other Than Income Taxes

Merchant energy taxes other than income taxes increased $23.7 million in 2005 compared to 2004 mostly due to $19.6 million related to higher gross receipts taxes at our retail electric operation and $4.0 million related to property taxes for Ginna.

Regulated Electric Business

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

Results

	2005	2004	2003
		(In millions)	
Revenues	**$ 2,036.5**	$ 1,967.7	$ 1,921.6
Electricity purchased for resale expenses	**(1,068.9)**	(1,034.0)	(1,023.5)
Operations and maintenance expenses	**(318.4)**	(304.2)	(305.1)
Merger-related transaction costs	**(4.0)**		
Workforce reduction costs			(0.6)
Depreciation and amortization	**(185.8)**	(194.2)	(181.7)
Taxes other than income taxes	**(135.3)**	(132.8)	(130.2)
Income from Operations	**$ 324.1**	$ 302.5	$ 280.5
Net Income	**$ 149.4**	$ 131.1	$ 107.5
Other Items Included in Operations (after-tax)			
Merger-related transaction costs	**$ (3.7)**		
Workforce reduction costs			(0.4)
Total Other Items	**$ (3.7)**	$	$ (0.4)

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 increased $18.3 million in 2005 compared to 2004 mostly because of the following:

- increased revenues less electricity purchased for resale expenses of $20.7 million after-tax,
- decreased depreciation and amortization expense of $5.1 million after-tax, and
- increased other income primarily due to gains on the sales of land of $3.6 million after-tax.

These favorable results were partially offset by the following:

- increased operations and maintenance expenses of $8.7 million after-tax mostly due to higher compensation and benefit costs and the impact of inflation on other costs, and
- merger-related transaction costs of $3.7 million after-tax.

Net income from the regulated electric business increased $23.6 million in 2004 compared to 2003 mostly because of the following:

- increased revenues less electricity purchased for resale expenses of $21.5 million after-tax,
- the absence of $19.4 million after-tax of incremental distribution service restoration expenses associated with Hurricane Isabel in 2003, and

lower interest expense of $10.0 million after-tax.

These favorable results were partially offset by the following:

excluding the costs associated with Hurricane Isabel, we had increased operations and maintenance expenses of $18.9 million after-tax mostly due to higher compensation and benefit costs, and the impact of inflation on other costs, higher uncollectible expenses, Sarbanes-Oxley 404 implementation costs, and increased spending on electric system reliability, and

increased depreciation and amortization expense of $7.6 million after-tax.

Electric Revenues

The changes in electric revenues in 2005 and 2004 compared to the respective prior year were caused by:

	2005	2004
	(In millions)	
Distribution volumes	**$ 21.3**	$ 15.8
Standard offer service	**38.8**	26.6
Total change in electric revenues from electric system sales	**60.1**	42.4
Other	**8.7**	3.7
Total change in electric revenues	**$ 68.8**	$ 46.1

Distribution Volumes

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 2005 and 2004 compared to the respective prior year were:

	2005	2004
Residential	**3.4%**	4.4%
Commercial	**5.1**	0.9
Industrial	**(6.4)**	(8.0)

In 2005, we distributed more electricity to residential customers compared to 2004 mostly due to warmer summer weather and an increased number of customers. We distributed more electricity to commercial customers mostly due to increased usage per customer, an increased number of customers, and warmer summer weather. We distributed less electricity to industrial customers mostly due to decreased usage per customer.

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

Standard Offer Service

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

Standard offer service revenues increased in 2005 compared to 2004 mostly because of increased standard offer service volumes to residential customers and increased standard offer service rates for all customers partially offset by lower standard offer service volumes associated with those commercial and industrial customers that elected alternative suppliers beginning July 1, 2004.

Standard offer service revenues increased in 2004 compared to 2003 mostly because of increased standard offer service volumes to residential customers, partially offset by lower revenues associated with commercial and industrial customers that elected an alternative supplier beginning July 1, 2004.

Electricity Purchased for Resale Expenses

BGE's actual costs of electricity purchased for resale expenses increased $34.9 million in 2005 compared to 2004 mostly because of increased standard offer service volumes to residential customers and higher costs to serve all standard offer service customers, partially offset by lower electricity purchased for resale expenses associated with commercial and industrial customers that elected alternative suppliers beginning July 1, 2004.

BGE's actual costs of electricity purchased for resale expenses increased $10.5 million in 2004 compared to 2003 mostly because of increased standard offer service volumes to residential customers and higher costs to serve all standard offer service customers, partially offset by lower electricity purchased for resale expenses associated with commercial and industrial customers that elected an alternative supplier beginning July 1, 2004.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $14.2 million in 2005 compared to 2004 mostly due to higher compensation and benefit costs and the impact of inflation on other costs.

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

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

Merger-Related Transaction Costs

We discuss our pending merger with FPL Group and related costs in more detail in *Note 15*.

Workforce Reduction Costs

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

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense decreased $8.4 million in 2005 compared to 2004 mostly because of the absence of $12.6 million of accelerated amortization expense associated with certain information technology assets replaced in 2004, partially offset by $4.2 million related to additional property placed in service.

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

Regulated Gas Business

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

Results

	2005	2004	2003
		(In millions)	
Revenues	**$ 972.8**	$ 757.0	$ 726.0
Gas purchased for resale expenses	**(687.5)**	(484.3)	(445.8)
Operations and maintenance expenses	**(131.8)**	(123.6)	(101.1)
Merger-related transaction costs	**(1.4)**		
Workforce reduction costs			