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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, 2010**

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

100 CONSTELLATION WAY, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-470-2800
(Registrants' telephone number, including area code)

1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY**	**52-0280210**

2 CENTER PLAZA, 110 WEST FAYETTE STREET, BALTIMORE, MARYLAND 21202
(Address of principal executive offices) (Zip Code)

410-234-5000
(Registrants' telephone number, including area code)

MARYLAND
(States of incorporation of both registrants)

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 Chicago Stock Exchange
Constellation Energy Group, Inc. Series A Junior Subordinated Debentures	New York Stock Exchange

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

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. o

Indicate by check mark whether Constellation Energy Group, Inc. has submitted electronically and posted on its corporate Web-site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark whether Baltimore Gas and Electric Company has submitted electronically and posted on its corporate Web-site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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

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

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

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

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

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

Aggregate market value of Constellation Energy Group, Inc. Common Stock, without par value, held by non-affiliates as of June 30, 2010 was approximately $6,490,790,907 based upon New York Stock Exchange composite transaction closing price.

CONSTELLATION ENERGY GROUP, INC. COMMON STOCK, WITHOUT PAR VALUE
199,850,572 SHARES OUTSTANDING ON JANUARY 31, 2011.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K	Document Incorporated by Reference
III	Certain sections of the Proxy Statement for the 2011 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, and the impact of such changes on our liquidity requirements,
- the liquidity and competitiveness of wholesale and retail markets for energy commodities,
- the conditions of the capital markets, interest rates, foreign exchange rates, availability of credit facilities to support business requirements, liquidity, and general economic conditions, as well as Constellation Energy Group's (Constellation Energy) and Baltimore Gas and Electric's (BGE) 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,
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets,
- the ability to successfully identify, finance, and complete acquisitions and sales of businesses and assets, including generating facilities, and to successfully invest in new business initiatives and markets,
- the effect of weather and general economic and business conditions on energy supply, demand, prices, and customers' and counterparties' ability to perform their obligations or make payments,
- the ability to attract and retain customers in our NewEnergy business and to adequately forecast their energy usage,
- the timing and extent of customer choice and competition in the energy markets and the rules and regulations adopted in those markets,
- regulatory or legislative developments federally, in Maryland, or in other states that affect energy competition, the price of energy, transmission or distribution rates and revenues, demand for energy, or increases in costs, including costs related to safety, or environmental compliance,
- the ability of our regulated and nonregulated businesses to comply with complex and/or changing market rules and regulations,
- the ability of BGE to recover all its costs associated with providing customers service,
- operational factors affecting our generating facilities, BGE's transmission and distribution facilities, or our other commercial operations, including 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, acts of war, catastrophic events, and other events beyond our control,
- the impact of industry consolidation,
- the impact of increased energy conservation and use of renewable energy,

- the actual outcome of uncertainties associated with assumptions and estimates requiring judgment when managing our business, 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, and

- cost and other effects of legal and administrative proceedings and other events that may not be covered by insurance, including environmental liabilities and liabilities associated with catastrophic events.

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

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

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PART I

Item 1. Business

Overview

Constellation Energy is an energy company that includes a generation business (Generation), a customer supply business (NewEnergy), and BGE, a regulated electric and gas public utility in central Maryland. 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 Generation business develops, owns, owns interests in, and operates electric generation facilities and a fuel processing facility located in various regions of the United States. This business also includes an operation that manages certain contractually controlled physical assets, including generating facilities and owns an interest in a joint venture that owns and operates nuclear generating facilities.

Our NewEnergy business is primarily a competitive provider of energy-related products and services for a variety of customers and focuses on selling electricity, natural gas, and other energy-related products to serve customers' requirements (load-serving), and providing other energy products and risk management services. This business also manages our upstream natural gas activities, designs, constructs, and operates renewable energy, heating, cooling, and cogeneration facilities and provides home improvements, sales of electric and gas appliances, and servicing of heating, air conditioning, plumbing, electrical, and indoor air quality systems.

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 10 counties in central Maryland. BGE was incorporated in Maryland in 1906.

On October 26, 2010, we reached a comprehensive agreement with EDF Group and affiliates (EDF) that restructured the relationship between our two companies, eliminated an outstanding asset put arrangement, and transferred to EDF the full ownership of our prior nuclear development joint venture, UniStar Nuclear Energy, LLC (UNE). We discuss this comprehensive agreement in more detail in *Note 4 to Consolidated Financial Statements*.

Operating Segments

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

Unaffiliated Revenues

	Generation	NewEnergy	Regulated Electric	Regulated Gas	Holding Company and Other
2010	8%	68%	19%	5%	%
2009	4	73	18	5	
2008	4	77	14	5	

Net (Loss) Income Attributable to Common Stock

	Generation	NewEnergy	Regulated Electric	Regulated Gas	Holding Company and Other
2010	(128)%	14%	10%	4%	%
2009	107	(9)	1	1	
2008	(27)	(76)		3	

	Total Assets					
	Generation	NewEnergy	Regulated Electric	Regulated Gas	Holding Company and Other	Eliminations
2010	49%	19%	26%	7%	4%	(5)%
2009	53	18	21	6	19	(17)
2008	50	32	21	6	15	(24)

Generation Business

We develop, own, operate, and maintain fossil and renewable generating facilities, hold a 50.01% interest in a nuclear joint venture that owns nuclear generating facilities, hold interests in qualifying facilities, and power projects in the United States and Canada totaling 9,030 MW as of December 31, 2010 (excludes our January 2011 acquisition of Boston Generating assets), and manage approximately 1,100 MW associated with certain of our long-dated tolling agreements. These agreements provide us with the contractual rights to purchase power from third party generation plants over an extended period of time. The output of our owned and contractually controlled plants is managed by our NewEnergy business and is hedged through a combination of power sales to wholesale and retail market participants. We also provide operation and maintenance services, including testing and start-up, to owners of electric generating facilities. Our NewEnergy business meets the load-serving requirements under various contracts using the output from our generating fleet and from purchases in the wholesale market.

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

Investment in Nuclear Generating Facilities

On November 6, 2009, we completed the sale of a 49.99% membership interest in Constellation Energy Nuclear Group LLC and affiliates (CENG), our subsidiary that owns our nuclear generating facilities

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described below. The total output of these nuclear facilities over the past three years is presented in the following table:

	Calvert Cliffs		Nine Mile Point		Ginna	
	MWH	Capacity Factor	MWH (1)	Capacity Factor	MWH	Capacity Factor
	(MWH in millions)					
2010	14.0	94%	12.6	93%	4.9	97%
2009	14.5	96	13.1	97	4.6	91
2008	14.7	96	12.8	94	4.7	94

(1)

Represents our and CENG's (after November 6, 2009) proportionate ownership interest

In connection with the closing of the transaction with EDF on November 6, 2009, we entered into a power purchase agreement (PPA) with CENG under which we will purchase 85 to 90% of the output that is not sold to third parties under pre-existing PPAs for an initial five year period. Additionally, pursuant to an amendment to the PPA entered into in 2010, beginning on January 1, 2015, and continuing to the end of the lives of the respective nuclear plants, we will purchase 50.01% and EDF will purchase 49.99% of the output of CENG's nuclear plants. We discuss this PPA in more detail in *Note 16 to Consolidated Financial Statements*.

Calvert Cliffs

CENG owns 100% of Calvert Cliffs Unit 1 and Unit 2. Unit 1 entered service in 1974 and is licensed to operate until 2034. Unit 2 entered service in 1976 and is licensed to operate until 2036.

Nine Mile Point

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

Nine Mile Point Unit 2 sells 90% of the plant's output to the former owners of the plant at an average price of approximately $35 per MWH under a PPA that terminates in November 2011. The PPA is 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 the output of Nine Mile Point Unit 2 is managed by CENG and sold primarily to us and EDF.

After termination of the Nine Mile Point Unit 2 PPA, a revenue sharing agreement with the former owners of the plant will begin and continue through November 2021. Under this agreement, which applies only to CENG's ownership percentage of Unit 2, a predetermined strike price is compared to the market price for electricity. If the market price exceeds the strike price, then 80% of this excess amount is shared with the former owners of the plant. The average strike price for the first year of the revenue sharing agreement is $40.75 per MWH. The strike price increases two percent annually beginning in the second year of the revenue sharing agreement. The revenue sharing agreement is unit contingent and is based on the operation of Unit 2.

CENG exclusively operates Unit 2 under an operating agreement with LIPA. LIPA is responsible for 18% of the operating costs (including decommissioning costs) and capital expenditures of Unit 2 and has representation on the Nine Mile Point Unit 2 management committee, which provides certain oversight and review functions.

Ginna

CENG owns 100% of the Ginna nuclear facility. Ginna entered service in 1970 and is licensed to operate until 2029. Ginna sells approximately 90% of the plant's output and capacity to the former owner for 10 years ending in 2014 at an average price of $44.00 per MWH under a long-term unit-contingent PPA. The remaining 10% of the output of Ginna is managed by CENG and sold into the wholesale market.

New Nuclear

In November 2010, as part of our comprehensive agreement with EDF to restructure the relationship between our two companies, we sold our 50% ownership interest in UNE to EDF. EDF is now the sole owner of UNE, and we will no longer have responsibility for developing or financing new nuclear projects through UNE. As discussed in *Note 4 to Consolidated Financial Statements*, we will cause CENG to transfer to UNE two potential new nuclear sites upon receipt of necessary approvals.

Qualifying Facilities and Power Projects

We hold up to a 50% voting interest in 15 operating energy projects, totaling approximately 758 MW, that consist of electric generation (primarily relying on alternative fuel sources), fuel processing, or fuel handling facilities. Thirteen of the electric generation projects are considered qualifying facilities under the Public Utility Regulatory Policies Act of 1978. Each electric generating plant sells its output to a local utility under long-term contracts.

Contracted Generation

We manage approximately 1,100 MWs under three agreements with third party generators in which we have long-dated contractual rights to purchase power from these third party generating plants. The economics of these transactions are similar to our owned generation.

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NewEnergy Business

We are a leading supplier of electricity, natural gas, and other energy products and services to wholesale and retail electric and natural gas customers.

To meet our customers' requirements, our NewEnergy business obtains energy from various sources, including:

- our generation assets,
- our contractually controlled generation assets,
- exchange-traded and bilateral power and natural gas purchase agreements,
- unit contingent power purchases from generation companies,
- 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 up to five years, and
- regional power pools.

During 2010, our NewEnergy business:

- supplied approximately 119 million megawatt hours (MWH) of aggregate electricity to distribution utilities, municipalities, and residential, commercial, industrial, and governmental customers,
- provided approximately 334 million British Thermal Units (mmBTUs) of natural gas to residential, commercial, industrial, and governmental customers, and
- delivered approximately 7.8 million tons of coal primarily to our own fleet.

Our NewEnergy business also manages certain contractually controlled physical assets, including generation facilities (excluding long-dated tolling agreements managed by our Generation business), and natural gas properties, provides risk management services, and trades energy and energy-related commodities. This business also provides the wholesale risk management function for our Generation business, as well as structured products and energy investment activities and includes our actual hedged positions with third parties.

Our NewEnergy business also manages our upstream natural gas activities, designs, constructs, and operates renewable energy, heating, cooling, and cogeneration facilities and provides home improvements, sales of electric and gas appliances, and servicing of heating, air conditioning, plumbing, electrical, and indoor air quality systems.

Wholesale Customer Supply

In 2010, our wholesale NewEnergy customer supply operation served approximately 57 million MWHs of wholesale full requirements electricity and related load-serving products.

Our wholesale NewEnergy customer supply operation structures transactions that serve the full energy and capacity requirements of various customers such as distribution utilities, municipalities, cooperatives and retail aggregators that do not own sufficient generating capacity or have in-house supply functions to meet their own load requirements.

Retail Customer Supply

During 2010, our retail NewEnergy customer supply operation served approximately 62 million MWHs of electricity load and approximately 334 million mmBTUs of natural gas.

Our retail NewEnergy customer supply operation structures transactions to supply full energy and capacity requirements and provide natural gas, transportation, and other energy products and services to commercial, industrial, governmental, and residential customers. Contracts with these customers generally extend from one to ten years, but some can be longer.

The retail NewEnergy customer supply operation combines a unified sales force with a customer-centric model that leverages technology to broaden the range of products and services we offer, which we believe promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which we believe will provide a platform that is scalable and able to capitalize on opportunities for future growth.

Structured Products

Our NewEnergy business uses energy and energy-related commodities and contracts in order to manage our portfolio of energy purchases and sales to customers through structured transactions. Our NewEnergy business assists customers with customized risk management products in the power, gas, coal, and freight markets (e.g., generation tolls and gas transport and storage).

Energy Investments

Our NewEnergy business has investments in energy assets that primarily include natural gas activities. Our NewEnergy business includes upstream (exploration and production) and downstream (transportation and storage) natural gas operations. Our upstream natural gas activities include the development, exploration, and exploitation of natural gas properties, as well as an approximately 28.5% interest in Constellation Energy Partners LLC (CEP), a limited liability company that we formed. CEP is principally engaged in the acquisition, development, and exploitation of natural gas properties. We no longer have any active involvement in the day-to-day operations of CEP.

Portfolio Management and Trading

Our NewEnergy business transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions. We use economic value

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at risk, which measures the market risk in our total portfolio, encompassing all aspects of our NewEnergy business, along with daily value at risk limits, stop loss limits, position limits, generation hedge ratios, and liquidity guidelines to restrict the level of risk in our portfolio.

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 use both derivative and nonderivative contracts in managing our portfolio of energy sales and purchase contracts. Although a substantial portion of our portfolio is hedged, we are able to identify opportunities to deploy risk capital to increase the value of our accrual positions, which we characterize as portfolio management.

Active portfolio management is intended to allow our NewEnergy business to:

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

We discuss the impact of our trading activities and economic value at risk in more detail in *Item 7. Management's Discussion and Analysis.*

Our portfolio management and trading activities involve the use of physical commodity inventories and a variety of instruments, including:

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

Beginning in the fourth quarter of 2008 and continuing throughout 2010, we reduced the risk and scale of our portfolio management and trading activities. Energy trading activities were scaled back and are being used primarily for hedging our Generation and NewEnergy businesses, price discovery and verification, and for deploying limited risk capital. These efforts materially impacted our portfolio management and trading activities' contribution to our operating results.

Fuel Sources

Our power plants use diverse fuel sources. Our plants' fuel mix based on capacity owned at December 31, 2010 and actual output by fuel type during 2010 was as follows:

Fuel	**Capacity Owned**	**Generation**
Nuclear (1)	21%	45%
Coal	30	37
Natural Gas	31	13
Oil	8	
Renewable and Alternative (2)	6	5
Dual (3)	4	

(1)

Reflects our 50.01% ownership interest in CENG.

(2)
Includes solar, hydro, waste coal, and biomass.

(3)
Switches between natural gas and oil.

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

Nuclear

CENG, our nuclear joint venture with EDF, owns the Calvert Cliffs, Nine Mile Point, and Ginna nuclear generating facilities.

The supply of fuel for these nuclear generating facilities includes the:

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

CENG has commitments that provide for quantities of uranium, conversion, enrichment, and fabrication of fuel assemblies to substantially meet expected requirements for the next several years at these nuclear generating facilities.

The uranium markets are competitive, and while prices can be volatile, CENG does not anticipate problems in meeting its future supply requirements.

Storage of Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982, as amended, ("NWPA") requires 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. Although the NWPA and CENG's contracts with the DOE required the DOE to begin taking possession of spent nuclear fuel no later than

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January 31, 1998, the DOE has failed to meet its obligation. The DOE's delay in taking possession of spent fuel has required CENG to undertake additional actions and incur costs to provide on-site dry fuel storage at all three of its nuclear sites. CENG has installed additional capacity at its independent spent fuel storage installation ("ISFSI") at Calvert Cliffs, has constructed an ISFSI at Ginna, and is constructing an ISFSI to be placed in service at Nine Mile Point in 2012.

Prior to 2010, the DOE had stated that it may not meet its obligation until 2020 at the earliest. During 2010, the DOE requested the withdrawal of its license application to use Yucca Mountain as a national repository for spent nuclear fuel. At this time, CENG is not able to determine whether the DOE will be able to commence meeting its obligation by 2020.

Each of CENG's plant subsidiaries have filed complaints against the federal government in the U.S. 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. The cases are currently stayed, pending litigation in other related cases. Any funds received from the DOE that represent the reimbursement of costs incurred prior to November 6, 2009, the date we sold a 49.99% membership interest in CENG to EDF, will belong to us, and any funds representing the reimbursement of costs incurred after November 6, 2009 will belong to CENG.

Cost for Decommissioning Nuclear Facilities

When Constellation Energy sold a 49.99% membership interest in CENG on November 6, 2009, we deconsolidated CENG for financial reporting purposes and, as a result, the decommissioning trust funds were removed from our Consolidated Balance Sheets. CENG is obligated to decommission its nuclear power plants after these plants cease operation.

Decommissioning activities are currently projected to be staged through the 2080 decade. Any changes in the costs or timing of decommissioning activities, or changes in the fund earnings, could affect the adequacy of the funds to cover the decommissioning of the plants, and if there were to be a shortfall, additional funding would have to be provided by CENG. CENG has the ability to request funding assistance from both Constellation Energy and EDF, as the owners of CENG.

Calvert Cliffs

In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Public Service Commission of Maryland (Maryland PSC), and certain State of Maryland officials. The settlement agreement became effective on June 1, 2008. Pursuant to the terms of the settlement agreement, BGE customers were relieved of the potential future liability for decommissioning Calvert Cliffs Unit 1 and Unit 2. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Maryland Senate Bill 1 which was enacted in June 2006.

Coal

We purchase the majority of our coal for electric generation under supply contracts with mine operators, and we acquire the remainder in the spot or forward coal markets. 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. 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)
Brandon Shores Units 1 and 2 (combined)	2,800,000
C. P. Crane Units 1 and 2 (combined) (1)	1,000,000
H. A. Wagner Units 2 and 3 (combined)	800,000

(1) *Assuming 100% sub-bituminous coal*

We receive coal deliveries to these facilities by rail and barge. Over the past few years, we expanded our coal sources through a variety of methods, including restructuring our rail and terminal contracts, increasing the range of coals we can consume, and finding potential other coal supply sources including limited shipments from various international sources. While we primarily use coal produced from mines located in central and northern Appalachia, we are using sub-bituminous coal from the Western United States at C.P. Crane and have the ability to switch to using imported coal at Brandon Shores and H.A. Wagner to manage our coal supply. 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.

As discussed in the *Environmental Matters* section, our Maryland coal-fired generating facilities must comply with the requirements of the Maryland Healthy Air Act (HAA), which requires reduction of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury emissions. To comply with the HAA requirements, we

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are planning to burn domestic and/or import compliance coals (1.2 lb/mmbtu SO_2 or less) at H.A. Wagner. The C.P. Crane station was converted to burn up to 100% sub-bituminous coal in June 2010. In March 2010, we completed installation of flue gas desulfurization (FGD) equipment on both Brandon Shores units. With the FGD installation, Brandon Shores now is able to burn higher sulfur coals (limit 6 lbs/mmbtu or approximately 3.5% sulfur) while simultaneously reducing station emissions. The blend of coals actually procured for Brandon Shores will be optimized to achieve the lowest delivered cost while complying with HAA limitations.

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. All of the Conemaugh and Keystone plants' annual coal requirements are purchased from regional suppliers on the open market. FGD equipment was installed on both of the Keystone units in 2009 and has been installed on both Conemaugh units since the mid-1990s. The FGD SO_2 restrictions on coal are 6 lbs/mmbtu (or approximately 3.7% sulfur) for the Keystone plant and approximately 4.9 lbs/mmbtu (or 3% sulfur) for the Conemaugh plant. The blend of coal procured is optimized to ensure compliance with station emission limits at the lowest delivered cost.

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

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

All of our coal requirements reflect expected generating 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. However, we believe that we will be able to obtain adequate quantities of coal to meet our requirements.

Gas

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

Oil

From 2008 through 2010, our requirements for residual fuel oil (No. 6) amounted to less than 0.5 million barrels of low-sulfur oil per year. Deliveries of residual fuel oil are made from the suppliers' Baltimore Harbor and Philadelphia marine terminals for distribution to the various generating plant locations. Also, based on normal burn practices, we require approximately 8.0 million to 11.0 million gallons of distillates (No. 2 oil and kerosene) annually, but these requirements can vary substantially from year to year depending upon the relationship between energy prices and fuel costs, weather conditions, and operating requirements. Distillates are purchased from the suppliers' Baltimore truck terminals for distribution to the various generating plant locations. We have contracts with various suppliers to purchase oil at spot prices, and for future delivery, to meet our requirements.

Competition

We encounter competition from companies of various sizes, having varying levels of experience, financial and human resources, and differing strategies.

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

With respect to our Generation business, 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, and banks), some of which have greater financial resources.

Many states are considering different types of regulatory initiatives concerning competition in the power and gas industry, which makes a general assessment of the state of competitive markets difficult. Many states continue to support or expand retail competition and industry restructuring. Other states that were considering restructuring have slowed their plans or postponed consideration of competitive markets. In addition, states that have restructured their energy markets routinely consider new market rules including return to monopoly service measures that could result in more limited opportunities for competitive energy suppliers like Constellation Energy. While there is activity in this area, we believe there is

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adequate growth potential in the current competitive market.

The market for commercial, industrial, and governmental energy supply continues to grow and we continue to experience increased competition from energy and non-energy market participants on a regional and national basis in our retail customer supply activities. Strong retail competition and the impact of wholesale power prices compared to the rates charged by local utilities affects the contract margin we receive from our customers. Recent economic conditions have increased overall margins reflecting an appropriate return on capital to support the business. Our experience and expertise in assessing and managing risk and our strong focus on customer service should help us to remain competitive during volatile or otherwise adverse market circumstances.

Generation and NewEnergy Operating Statistics

	2010	2009	2008
Gross Margin *(In millions)*			
Generation (1)	**$ 800**	$ 2,082	$ 2,042
NewEnergy	**1,244**	1,079	1,040
Total Gross Margin	**$ 2,044**	$ 3,161	$ 3,082
Generation *(In millions)* MWH (1)(2)	**35.1**	46.0	50.9

Operating statistics do not reflect the elimination of intercompany transactions.

(1) *2009 reflects our 100% ownership in our nuclear business through November 6, 2009 and our 50.01% ownership in our nuclear business from November 6, 2009 through December 31, 2009 following the sale of a 49.99% membership interest in CENG. These amounts also exclude contracted generation.*

(2) *These amounts exclude contracted generation.*

Baltimore Gas and Electric Company

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

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

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

Electric Business

Electric Competition

Maryland has implemented electric customer choice and competition among electric suppliers. As a result, all customers can choose their electric energy supplier, which includes subsidiaries of Constellation Energy. While BGE does not sell electricity to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance.

Standard Offer Service

BGE is obligated by the Maryland PSC to provide market-based standard offer service (SOS) to all of its electric customers who elect not to select a competitive energy supplier. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a shareholder return component and an incremental cost component. As discussed in *Item 7. Management's Discussion and Analysis Regulated Electric Business* section, BGE resumed collection of the shareholder return portion of the residential SOS administrative charge, which had been eliminated under Maryland Senate Bill 1, from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. Starting June 1, 2010, BGE provides all residential electric customers a credit for the residential return component of the administrative charge through December 2016.

Bidding to supply BGE's SOS occurs from time to time through a competitive bidding process approved by the Maryland PSC. Successful bidders, which may include subsidiaries of Constellation Energy, execute contracts with BGE for terms of three months or two years.

Commercial and Industrial Customers

BGE is obligated by the Maryland PSC to provide several variations of SOS to commercial and industrial customers depending on customer load.

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Residential Customers

Residential customers went to full market rates in January 2008. Pursuant to the order issued by the Maryland PSC in October 2009 approving our transaction with EDF, Constellation Energy agreed to fund a one-time per customer distribution rate credit for BGE residential customers, in 2010, totaling $110.5 million, which approximated $100 per customer. In December 2009, BGE filed a tariff with the Maryland PSC stating we would give residential customers a rate credit of exactly $100 per customer. As a result, BGE provided rate credits totaling $112.4 million. Constellation Energy made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as required by the Maryland PSC order.

In 2010, the Maryland PSC issued a rate order authorizing BGE to increase electric and gas distribution rates for service rendered on or after December 4, 2010. We discuss this rate order in more detail in *Item 7. Management's Discussion and Analysis Regulation Maryland Base Rates* section.

Electric Load Management

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

- two options for commercial and industrial customers to reduce their electric loads,
- air conditioning and heat pump controls for residential and commercial customers through both programmable thermostats and load control devices, and
- residential water heater controls.

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

In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of approximately $480 million. Under a grant from the DOE, BGE is a recipient of $200 million in federal funding for our smart grid and other related initiatives. This grant allows BGE to be reimbursed for smart grid and other related expenditures up to $200 million, substantially reducing the total cost of these initiatives.

The Maryland PSC approved a full portfolio of conservation programs for implementation in 2009 as well as a customer surcharge to recover the associated costs.

Transmission and Distribution Facilities

BGE maintains approximately 240 substations and approximately 1,300 circuit miles of transmission lines throughout central Maryland. BGE also maintains approximately 24,800 circuit miles of distribution lines. The transmission facilities are connected to those of neighboring utility systems as part of PJM Interconnection (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.

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BGE Electric Operating Statistics

	2010	2009	2008
Revenues *(In millions)*			
Residential			
Excluding Delivery Service Only	**$ 1,808.6**	$ 1,864.0	$ 1,688.3
Delivery Service Only	**48.1**	14.3	7.6
Commercial			
Excluding Delivery Service Only	**467.4**	531.2	604.0
Delivery Service Only	**249.5**	245.0	222.8
Industrial			
Excluding Delivery Service Only	**28.7**	30.4	31.3
Delivery Service Only	**25.6**	29.1	27.1
System Sales and Deliveries	**2,627.9**	2,714.0	2,581.1
Other (1)	**124.4**	106.7	98.6
Total	**$ 2,752.3**	$ 2,820.7	$ 2,679.7
Distribution Volumes *(In thousands)* MWH			
Residential			
Excluding Delivery Service Only	**12,344**	12,394	12,670
Delivery Service Only	**1,490**	457	353
Commercial			
Excluding Delivery Service Only	**3,707**	3,945	3,957
Delivery Service Only	**12,537**	11,753	11,739
Industrial			
Excluding Delivery Service Only	**267**	270	242
Delivery Service Only	**2,519**	2,757	3,002
Total	**32,864**	31,576	31,963
Customers *(In thousands)*			
Residential	**1,114.7**	1,111.9	1,108.5
Commercial	**118.6**	118.5	117.6
Industrial	**5.5**	5.3	5.3
Total	**1,238.8**	1,235.7	1,231.4

(1) *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 electricity that was purchased by the customer from an alternate supplier.

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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.

A market-based rates incentive mechanism applies to customers that buy their gas from BGE. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE must secure fixed-price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism.

BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements.

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

BGE's current maximum storage entitlements are 297,091 DTH per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

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

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

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

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

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BGE Gas Operating Statistics

	2010	2009	2008
Revenues *(In millions)*			
Residential			
Excluding Delivery Service Only	**$ 427.0**	$ 460.7	$ 567.8
Delivery Service Only	**22.1**	19.0	19.0
Commercial			
Excluding Delivery Service Only	**109.0**	129.1	161.8
Delivery Service Only	**39.8**	40.4	46.4
Industrial			
Excluding Delivery Service Only	**5.2**	6.4	8.1
Delivery Service Only	**16.7**	15.2	14.5
System Sales and Deliveries	**619.8**	670.8	817.6
Off-System Sales	**79.8**	81.1	197.7
Other	**9.8**	6.4	8.7
Total	**$ 709.4**	$ 758.3	$ 1,024.0
Distribution Volumes *(In thousands)* DTH			
Residential			
Excluding Delivery Service Only	**37,791**	37,889	37,675
Delivery Service Only	**4,857**	4,270	4,119
Commercial			
Excluding Delivery Service Only	**11,606**	12,066	12,205
Delivery Service Only	**24,329**	25,046	29,289
Industrial			
Excluding Delivery Service Only	**595**	635	650
Delivery Service Only	**19,750**	20,826	18,432
System Sales and Deliveries	**98,928**	100,732	102,370
Off-System Sales	**14,711**	17,542	18,782
Total	**113,639**	118,274	121,152
Customers *(In thousands)*			
Residential	**608.6**	606.8	605.0
Commercial	**42.9**	42.9	42.8
Industrial	**1.1**	1.1	1.1
Total	**652.6**	650.8	648.9

Operating statistics do not reflect the elimination of intercompany transactions.
"Delivery service only" refers to BGE's delivery of gas that was purchased by the customer from an alternate supplier.

Franchises

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

Consolidated Capital Requirements

Our total capital requirements for 2010 were $1.0 billion. Of this amount, $0.4 billion was used in our Generation and NewEnergy businesses and $0.6 billion was used in our regulated business. We estimate our total capital requirements will be $1.0 billion in 2011.

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.

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We continuously monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance. Our capital expenditures were approximately $1.2 billion during the five-year period 2006-2010 to comply with existing environmental standards and regulations, including the Maryland HAA. Our estimated environmental capital requirements for the next three years are approximately $35 million in 2011, $20 million in 2012, and $25 million in 2013.

Air Quality

Federal

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

National Ambient Air Quality Standards (NAAQS)

The NAAQS are federal air quality standards authorized under the CAA that establish maximum ambient air concentrations for the following specific pollutants: ozone (smog), carbon monoxide, lead, particulates, SO_2, and nitrogen dioxide.

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.

In December 2008, the United States Court of Appeals for the District of Columbia Circuit reversed its July 2008 decision to fully vacate CAIR, and instead, remanded the issue to the EPA for reconsideration with CAIR requirements to remain in effect until the EPA takes further action. The uncertainty around the adoption of CAIR has not resulted in a material change to our emissions reduction plan in Maryland as the emissions reduction requirements of Maryland's HAA and Clean Power Rule (CPR) are more stringent and applied sooner than those under CAIR. However, as CAIR is replaced, it could affect the market prices of SO_2 and NO_x emission allowances, which could in turn affect our financial results.

In July 2010, the EPA proposed regulations to replace the regional cap-and-trade program under CAIR with a program that would require each of 31 eastern states and the District of Columbia to reduce SO_2 and NO_X emissions. Depending on the scope of any final regulations that may be adopted by the EPA, which is expected to occur in July 2011, and any plans that may be adopted by the states in which our plants are located, additional regulation could result in additional compliance requirements and costs that could be material.

In January 2010, the EPA proposed rules to adopt NAAQS for ozone that are stricter than the NAAQS adopted in March 2008, based on the EPA's reevaluation of scientific evidence about ozone and ozone's effects on humans and the environment. The final standard is expected to be adopted in 2011. In June 2010, the EPA adopted a stricter NAAQS for SO_2. We are unable to determine the impact that complying with the stricter NAAQS for ozone or SO_2 will have on our financial results until the states in which our generating facilities are located adopt plans to meet the new standards. However, costs associated with compliance with these plans could be material.

In December 2006, the United States Court of Appeals for the District of Columbia Circuit ruled that requirements to impose fees on large emissions sources in areas that have not attained the NAAQS based on the previous ozone standard (Section 185 fees), which had been rescinded by the EPA in May 2005, remained applicable retroactive to November 2005 and remanded the issue to the EPA for reconsideration. A petition to the United States Supreme Court to hear an appeal was denied in January 2008. The EPA issued Section 185 fee guidance to the states in January 2010 that contained flexible state alternatives to meet the requirements. States in which we operate have not finalized their approach for implementing the requirements and consequently, we are unable to estimate the ultimate financial impact of this matter in light of the uncertainty surrounding the anticipated EPA and state rulemakings. However, the final resolution of this matter, and any fees that are ultimately assessed could have a material impact on our financial results.

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

Hazardous Air Pollutant Emissions

In March 2005, the EPA finalized the Clean Air Mercury Rule (CAMR) to reduce the emissions of mercury from coal-fired facilities through a market-based cap and trade program. CAMR was to affect all coal or waste coal fired boilers at our generating facilities. However, in February 2008, the United States Court of Appeals for the District of Columbia Circuit struck down CAMR. In response to that decision and as a result of a court settlement with a number of parties, the EPA is under a consent order to propose a rule by March 2011 and to finalize new hazardous air pollutant emission standards by November 2011. Any new standards that require the installation of additional emissions control technology beyond what is required under Maryland's HAA and CPR, which are discussed

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below, may require us to incur additional costs, which could have a material effect on our financial results.

New Source Review

In connection with its enforcement of the CAA's new source review requirements, in 2000, the EPA requested information relating to modifications made to our Brandon Shores, C.P. Crane, and H. A. Wagner plants located in Maryland. The EPA also sent similar, but narrower, information requests to Keystone and Conemaugh, two of our newer Pennsylvania coal burning plants in which we have an ownership interest. We responded to the EPA in 2001, and as of the date of this report the EPA has taken no further action.

As discussed in *Note 12 to Consolidated Financial Statements*, in January 2009, the EPA issued a Notice of Violation to one of our subsidiaries alleging that the Keystone plant located in Pennsylvania, of which we own a 20.99% interest, performed various capital projects without complying with the new source review requirements.

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

State

Maryland has adopted the HAA and the CPR, which establish annual SO_2, NO_x, and mercury emission caps for specific coal-fired units in Maryland, including units located at three of our facilities. The requirements of the HAA and the CPR for SO_2, NO_x, and mercury emissions are more stringent and apply sooner than those required under federal requirements. Likewise, Massachusetts has comprehensive air emissions standards in place that are more stringent than the federal standards, so impending regulations are not anticipated to cause additional costs to our natural gas and oil-fired units in Massachusetts. In Pennsylvania, regulations adopted requiring coal-fired generating facilities to reduce mercury emissions were ruled invalid by a Pennsylvania court in January 2009.

Maryland has also adopted opacity regulations consistent with its commitment to resolve long-standing industry concerns about the prior regulations' continuous compliance requirements and is in the process of obtaining the EPA's approval of Maryland's state implementation plan (SIP) for these regulations. While EPA approval of Maryland's SIP is being obtained, the opacity regulations are being implemented in a manner that will enable our plants to remain in compliance. We anticipate that the regulations under the EPA-approved SIP will be consistent with the regulations as currently implemented.

Capital Expenditure Estimates Air Quality

We expect to incur additional environmental capital spending as a result of complying with the air quality laws and regulations discussed above. To comply with HAA and CPR, we will install additional air emission control equipment at our coal-fired generating facilities in Maryland and at our co-owned coal-fired facilities in Pennsylvania to meet air quality standards. We include in our estimated environmental capital requirements capital spending for these air quality projects, which we expect will be approximately $20 million in 2011, $15 million in 2012, $25 million in 2013 and $25 million from 2014-2015.

Our estimates are subject to significant uncertainties including the timing of any additional federal and/or state regulations or legislation, such as any regulations adopted by the EPA in response to the court decision striking down CAMR, the implementation timetables for such regulation or legislation, and the specific amount of emissions reductions that will be required at our facilities. As a result, we cannot predict our capital spending or the scope or timing of these projects with certainty, and the actual expenditures, scope, and timing could differ significantly from our estimates.

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

Global Climate Change

In response to the anticipated challenges of global climate change, we believe it is imperative to slow, stop and reverse the growth in greenhouse gas emissions. Climate change could pose physical risks, such as more frequent or more extreme weather events, that could affect our systems and operations; however, uncertainty remains as to the timing and extent of any direct, climate-related impacts to our systems and operations. Extreme weather can affect the supply of and demand for electricity, natural gas and fuels and these changes may impact the price of energy commodities in both the spot market and the forward market, which may affect our financial results. In addition, extreme weather typically increases demand for electricity and gas from BGE's customers.

There is continued likelihood that greenhouse gas emissions regulation will eventually occur at the international or federal level and/or continue to occur at the state level although considerable uncertainty remains as to the nature and timing of such regulation. Climate-related legislation was introduced in the last several United States Congress sessions but was not enacted. In September 2009, the EPA issued an "endangerment and cause or contribute finding" for greenhouse gases under the Clean Air Act and in 2010 finalized changes to its air construction and operating permit programs to incorporate greenhouse gases as pollutants subject to air permits. Beginning in 2011, in certain instances, additional greenhouse gas emissions resulting from the construction or modification of large facilities subject to the EPA's permit programs, which include power plants, will be required to be controlled through the use of the best available control technology, as determined by the EPA, before an air emissions permit will be issued. If we were to modify our generating plants, our costs to comply with these requirements could be material depending on the modifications made.

Maryland and Massachusetts are participants in the Northeast Regional Greenhouse Gas Initiative (RGGI). Under RGGI, the states auction carbon dioxide (CO_2) allowances associated with power plants, which include plants owned by us. Auctions have occurred quarterly since September 2008. Although we did not incur material costs in these auctions, we could incur material costs in the future to purchase allowances necessary to offset CO_2 emissions from our plants. Although we participate in RGGI, we believe a patchwork of climate policy and regulatory approaches across different states, regions or industry sectors has the potential to inequitably raise costs to particular businesses and/or drive the reallocation of emissions without actually achieving the desired overall reduction of emissions.

In addition, California has adopted regulations requiring our generating facilities in California to submit greenhouse gas emissions data to the state. More recently, in December 2010, the California Air Resources Board approved a declining cap and trade program for electricity suppliers beginning in 2012 aimed at achieving a 15% reduction in CO_2 emissions by 2020 as compared with 2012. It is not possible to determine the scope of the impact of this program on our business or financial results until the details of the program are made public, but the impact could be material.

We continue to monitor international developments and proposed federal and state legislation and regulations and evaluate the potential impact on our operations. In the event that additional greenhouse gas emissions reduction legislation or regulations are enacted, we will assess our various compliance alternatives, which may include installation of additional environmental controls, modification of operating schedules or the closure of one or more of our coal-fired generating facilities, and our compliance costs could be material.

However, to the extent greenhouse gas emissions are regulated through a federal, mandatory cap and trade greenhouse gas emissions program, we believe our business could also benefit. Our generation fleet has an overall CO_2 emission rate that is lower than the industry average with a substantial amount of the fleet's output coming from nuclear and hydroelectric plants, which generate significantly lower CO_2 emissions than fossil fuel plants. We also have experience trading in the markets for emissions allowances and renewable energy credits and our NewEnergy business has expertise in providing renewable energy products and services to retail customers.

Water Quality

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

Water Intake Regulations

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

In response to this ruling, in July 2007, the EPA suspended the second phase of the regulations pending further rulemaking and directed the permitting authorities to establish controls for cooling water intake structures that reflect the best technology available for minimizing adverse environmental impacts. In December 2008, the United States Supreme Court heard an appeal of the Second Circuit's decision relating to the application of cost-benefit analysis to best technology available decisions and ruled in April 2009 that the EPA has a right to consider cost-benefit analysis in such decisions.

The EPA is expected to propose new regulations in March 2011 and we will evaluate our compliance options in light of those proposed regulations. Until the new regulations are finalized, which is expected in July 2012, water intake compliance will be determined in accordance with the EPA's July 2007 order and relevant state regulations and interpretations. Depending on the scope of any new regulations that may be adopted by the EPA, our compliance costs could be material.

In March 2010, the New York Department of Environmental Conservation issued a draft policy designating closed-cycle cooling as the best technology available for cooling water intake structures for minimizing adverse environmental impacts. At this time we cannot predict whether this policy will be adopted. However, if the policy is adopted and CENG is required to retrofit its two nuclear generating facilities in New York to implement this technology, our share of the compliance costs could be material.

Hazardous and Solid Waste

Our coal-fired generating facilities produce approximately two and a half million tons of combustion by-products ("ash") each year. The EPA announced in 2007 its intention to develop national standards to regulate this material as a non-hazardous waste, and has been developing or considering regulations governing the placement of ash in landfills, surface impoundments, sand/gravel surface mines and coal mines. In 2009, following the Tennessee Valley Authority ash release, the EPA announced it is considering regulating ash as a hazardous waste. Depending on its final scope, additional federal regulation has the potential to result in additional compliance requirements and costs that could be material. In addition, the Maryland Department of the Environment finalized regulations governing the disposal, storage, use and placement of ash in December 2008.

As a result of these regulatory proposals and our current ash generation projections, we are exploring our options for the management of ash, including construction of an ash placement facility. Over the next five years, we estimate that our capital expenditures for this project will be approximately $20 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.

In May 2010, the EPA proposed rules to regulate coal combustion by-products, such as fly ash, either as a special hazardous waste or as a nonhazardous waste. Depending on the scope of any final rules that are adopted, additional federal regulation has the potential to result in additional compliance requirements and costs that could be material.

Employees

Constellation Energy and its consolidated subsidiaries (excluding CENG, which was deconsolidated on November 6, 2009) had approximately 7,600 employees at December 31, 2010.

Available Information

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

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

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

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.

Economic conditions and instability in the financial markets could negatively impact our business.

Our operations are affected by local, national, and worldwide economic conditions. The consequences of a slow recovery from recession or a new recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity may continue to result in a decline in energy consumption, an increase in customers' inability to pay their accounts, and lower commodity prices. These impacts may adversely affect our financial results and future growth.

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Instability in the financial markets, as a result of recession or otherwise, may affect the cost of capital and our ability to raise capital. We rely on the capital and banking markets, as well as the periodic use of commercial paper to the extent available, to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit issued under our credit facilities to support our operations. Disruptions in the capital and credit markets as a result of uncertainty, reduced alternatives, or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses, including our ability to secure credit facilities and refinance debt that comes due, and our ability to complete other alternatives we are exploring. In addition, such disruptions could adversely affect our ability to draw on our credit facilities. Our access to funds under those credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to us if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from borrowers within a short period of time. The disruptions in capital and credit markets may also result in higher interest rates on publicly issued debt securities and increased costs associated with commercial paper borrowing and under bank credit facilities.

Any disruptions could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, further changing our strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash. The inability to obtain the liquidity needed to meet our business requirements, or to obtain such liquidity on terms that are favorable to us, would have a material adverse effect on our business, results of operations and financial condition. If entities with which we do business are unable to raise capital or access the credit markets, they may be unable to perform their obligations or make payments under agreements we have with them. Defaults by these entities may have an adverse effect on our financial results.

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

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

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

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

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

Exposure to fuel cost volatility. Currently, our power generation facilities purchase a portion of their fuel through short-term contracts or on the spot market. Fuel prices can be volatile, and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs. In addition, new sources of natural gas supplies from domestic shale production, as well as rising liquid natural gas (LNG) exports, could increase the long-term supply of natural gas and create a fundamental and long-lasting decline in natural gas prices. Lower natural gas prices could contribute to a decline in power generation prices that could have an adverse effect on our financial results and cash flows. As a result, fuel price changes may adversely affect our financial results.

Exposure to counterparty performance. Our NewEnergy business enters into transactions with numerous third parties (commonly referred to as "counterparties"). In these arrangements, we are exposed to the credit risks of our counterparties and the risk that one or more counterparties may fail to perform under their obligations to make payments or deliver fuel or power. In addition, we enter into various wholesale transactions through Independent System Operators (ISOs). These ISOs are exposed to counterparty credit

risks. Any losses relating to counterparty defaults impacting the ISOs are allocated to and borne by all other market participants in the ISO. These risks are exacerbated during periods of commodity price fluctuations. If a counterparty were to default and we were to liquidate all contracts with that entity, our credit loss would include the loss in value of derivative contracts recorded at fair value, the amount owed for settled transactions, and additional payments, if any, that we would have to make to settle unrealized losses on accrual contracts. Defaults by suppliers and other counterparties may adversely affect our financial results.

Changes in the prices of commodities, initial margin requirements, collateral posting asymmetries and types of collateral impact our liquidity requirements.

Our businesses are exposed to market fluctuations in the price and transportation costs of electricity, natural gas, coal, and other commodities. We seek to mitigate the effect of these fluctuations through various hedging strategies, which may require the posting of collateral by both us and our counterparties. Changes in the prices of commodities and initial margin requirements for exchange-traded contracts can affect the amount of collateral that must be posted, depending on the particular position we hold.

There are certain asymmetries relating to the use of collateral that create liquidity requirements for our Generation and NewEnergy businesses. These asymmetries arise as a result of our actions to be economically hedged as well as market conditions or conventions for conducting business that result in some transactions being collateralized while others are not, including:

- In our NewEnergy business, we generally do not receive collateral under contractual obligations to supply our customers, but we may hedge these transactions through purchases that generally require us to post collateral.
- In our Generation operation, we may have to post collateral on our power sale or fuel purchase contracts.

As a result, significant changes in the prices of commodities and margin requirements for exchange-traded contracts could require us to post additional collateral from time to time without our counterparties having to post cash collateral to us, which could adversely affect our overall liquidity and ability to finance our operations, and, in turn, could adversely affect our credit ratings. Additionally, posting letters of credit to counterparties to meet collateral requirements adversely impacts our liquidity, while the receipt of letters of credit as collateral does not improve our liquidity.

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

We are an active participant in energy markets through our competitive energy businesses. The liquidity of regional energy markets is an important factor in our ability to manage risks in these operations. Over the past several years, market participants in the merchant energy business 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, which, in turn, has impacted our ability to enter into certain types of transactions to manage our risks for settlement periods beyond 18 to 24 months. Liquidity in the energy markets can be adversely affected by various factors, including price volatility and the availability of credit. As a result, future reductions in liquidity may restrict our ability to manage our risks and this could impact our financial results.

We 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.

We may not fully hedge our Generation and NewEnergy businesses, 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 obligations. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. However, we may not cover the entire exposure of our assets or positions to market price volatility, and the coverage will vary over time. Fluctuating commodity prices may negatively impact our financial results to the extent we have unhedged positions.

In addition, risk management tools and metrics such as economic value at risk, daily value at risk, and stress testing are based on historical price movements. If price movements significantly or persistently deviate

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from historical behavior, risk limits may not fully protect us from significant losses.

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

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

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

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

Additionally, the settlement of derivative instruments could reflect a realized value that differs from our reported estimates of fair value.

Inaccurate assumptions and estimates in the models we use could adversely impact our financial results.

We deploy many models to value merchant contracts, derivatives and assets, to dispatch power from our generation plants, and to measure the risks and costs of various transactions and businesses. Also, a significant portion of our business relies on the assumptions underlying the forecasting of customer load, correlations between prices of energy commodities and weather and the creditworthiness of our customers and other third parties. Inaccurate estimates of various business assumptions used in those models could create the mispricing of customer contracts and assets or the incorrect measurement of key risks relating to our portfolios and businesses that could adversely impact our financial results.

Poor market performance will affect our pension plan investments, which may adversely affect our liquidity and financial results.

At December 31, 2010, our qualified pension obligation was approximately $129 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 or the failure of those assets to earn an adequate return may increase our funding requirements for these obligations, which may adversely affect our liquidity and financial results.

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

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

Our Generation business may incur substantial costs and liabilities due to our ownership interest in nuclear generating facilities.

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

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

- mechanical or structural problems;

inadequacy or lapses in maintenance protocols;

impairment of reactor operation and safety systems due to human or mechanical error;

costs of storage, handling and disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel;

regulatory actions, including shut down of units because of public safety concerns, whether at our plants or other nuclear operators;

limitations on the amounts and types of insurance coverage commercially available;

- uncertainties regarding both technological and financial aspects of decommissioning nuclear generating facilities; and
- environmental risks, including risks associated with changes in environmental legal requirements.

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

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.

Examples of potential future regulatory changes include additional regulation of greenhouse gas emissions at the federal, regional, and/or state level, heightened enforcement of new source review requirements, increased regulation of coal combustion by-products, and mandated investment in maximum achievable control technology or renewable energy resources. One or more of these changes could increase our compliance and operating costs or require significant commitments of capital.

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

We are subject to regulation by federal and state governmental entities, including the FERC, the NRC, the Maryland PSC and the utility commissions of other states in which we have operations. In addition, changing governmental policies and regulatory actions can have a significant impact on us. Regulations can affect, for example, allowed rates of return, requirements for plant operations, recovery of costs, limitations on dividend payments, and the regulation or re-regulation of wholesale and retail competition.

BGE's distribution rates are subject to regulation by the Maryland PSC, and such rates are effective until new rates are approved. If the Maryland PSC does not approve adequate new rates, BGE might not be able to recover certain costs it incurs or earn an adequate rate of return. In addition, limited categories of costs are recovered through adjustment charges that are periodically reset to reflect current and projected costs. Inability to recover material costs not included in rates or adjustment clauses could have an adverse effect on our, or BGE's, cash flow and financial position.

Energy legislation enacted in Maryland in June 2006 and April 2007 mandated that the Maryland PSC review Maryland's competitive electricity market. Although the settlement agreement reached with the State of Maryland in March 2008 terminated certain studies relating to the 1999 deregulation settlement, the State of Maryland is still undertaking a review of the Maryland electric industry and market structure to consider various options for providing standard offer service to residential customers, including re-regulation. We cannot at this time predict the final outcome of this review or how such outcome may affect our, or BGE's financial results, but it could be material.

The Dodd-Frank Wall Street Reform and Consumer Protection Act provides for a new regulatory regime for derivatives. Final regulations may address collateral requirements, exchange margin cash postings, and other aspects of derivative transactions, which if applicable to us despite being an end user of derivatives, could require us to post additional cash collateral or otherwise have a material adverse effect on our business.

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We are also subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation (NERC) and enforced by the FERC. Compliance with the mandatory reliability standards may subject us to higher operating costs and may result in increased capital expenditures. If we are found to be in noncompliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. The State of Maryland also is considering legislative or regulatory changes that would impose reliability and quality of service standards on electric and gas companies, including penalties for failure to meet those standards.

Further, federal and/or state regulatory approval may be necessary for us to complete transactions. As part of the regulatory approval process, governmental entities may impose terms and conditions on the transaction or our business that are unfavorable or add significant additional costs to our future operations.

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

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

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

Energy companies have been under increased scrutiny by state legislatures, regulatory bodies, capital markets, and credit rating agencies. This increased scrutiny could lead to substantial changes in laws and regulations affecting us, including modifications to the auction processes in competitive markets and new accounting standards that could change the way we are required to record revenues, expenses, assets, and liabilities. Proposals in the State of Maryland from time to time relating to the structure of the electric industry in Maryland and various options for re-regulation of the industry are examples of how these laws and regulations can change. In addition, other states are seeking more direct ways to affect the results of wholesale capacity markets, including legislation adopted in New Jersey that provides guaranteed cost recovery for the development of up to 2,000 MWs of generation in exchange for the new generation clearing in the PJM capacity market. We cannot predict the future development of regulation or legislation in these markets or the ultimate effect that this changing regulatory environment will have on our business.

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

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

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

BGE's electric and gas infrastructure may require significant expenditures to maintain and is subject to operational failure, which could result in potential liability.

Much of BGE's electric and gas operational systems and infrastructure, such as gas mains and pipelines and electric transmission and distribution equipment, has been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including due to events that are beyond BGE's control, and may require significant expenditures to operate efficiently. Operational failure could result in potential liability if such failure results in damage to property or injury to individuals. As a result, electric and gas infrastructure expenditures and operational failure of equipment could have an adverse effect on our, or BGE's, financial results.

Our NewEnergy 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 reduced revenues and increased operating costs to our business.

Our NewEnergy business has contractual obligations to certain customers to supply full requirements service to such customers to satisfy all or a portion of their energy requirements. The uncertainty regarding the amount of load that our NewEnergy business must be prepared to supply to customers may increase our operating costs. The process of estimating the load requirements of our

customers is complicated by potential variability in demand resulting from extreme changes in weather and economic factors affecting our customers. A significant under- or over-estimation of load requirements could result in our NewEnergy business not having enough power 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 reduce our revenues and/or increase our operating costs and result in the possibility of reduced earnings or incurring losses.

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

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

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

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

Investment in new business initiatives and markets may not be successful.

Our NewEnergy business has sought to invest in new business initiatives and actively participate in new markets. These include, but are not limited to, unconventional oil and gas exploration and production, residential retail power and gas sales, solar and wind generation, and managed load response. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. Due to these risks, no assurance can be given that such initiatives will be successful and will not materially adversely affect our financial results. Additionally, as these markets mature, there may be new market entrants or expansion by established competitors that increase competition for customers and resources, which could result in us not achieving our plans and could have a material adverse effect on our financial results.

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

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

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

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

We are likely to encounter significant competition for acquisition opportunities that may become available. In addition, we may be unable to identify attractive acquisition opportunities at favorable prices, to secure the financing necessary to undertake them, or to successfully and timely complete and integrate them. Specifically, we intend to continue to pursue the acquisition of new generating plants in regions where we have significant retail and wholesale customer supply operations. Acquired plants may not generate the projected rates of return or sufficiently match generation capacity with retail and wholesale customer supply operations volumes causing an increase in collateral requirements. If we cannot identify, complete and integrate acquisitions successfully, our business, results of operations and financial condition could be adversely affected.

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War, threats of terrorism and catastrophic events may impact the results of our operations in unpredictable ways.

We cannot predict the impact that any future act of war, terrorist attack, or catastrophic event might 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, war, or a catastrophic event may affect our operations. Furthermore, these catastrophic events could compromise the physical or cyber security of our facilities, which could adversely affect our ability to manage our business effectively.

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 war, threats of terrorism, and catastrophic events may affect our stock price and our ability to raise capital.

In addition, we maintain a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that may damage or destroy assets or interrupt operations. Furthermore, in the event of a severe disruption resulting from war, threats of terrorism, and catastrophic events, we have contingency plans and employ crisis management to respond and recover operations. Despite these measures, there may be events beyond our control that may severely impact operations and affect financial performance.

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

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 in the commercial paper markets, if available, could be hindered, and our borrowing costs would increase. Additionally, the business prospects of our wholesale and retail NewEnergy business, which in many cases rely on the creditworthiness of Constellation Energy, would be negatively impacted. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade. Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post collateral in an amount that exceeds our available liquidity. Some of the factors that affect credit ratings are cash flows, liquidity, the amount of debt as a component of total capitalization, and political, legislative, and regulatory events.

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

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

Item 2. Properties

Constellation Energy occupies approximately 856,000 square feet of leased and owned office space in North America, which includes its corporate offices in Baltimore, Maryland. We describe our electric generation properties on the next page. We also have leases for other offices and services located in the Baltimore metropolitan region, and for various real property and facilities relating to our generation projects.

BGE owns its principal headquarters building located in downtown Baltimore. BGE also leases approximately 16,670 square feet of office space. 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.

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

Our NewEnergy business owns several natural gas producing properties.

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The following table describes our generating facilities:

Plant	Location	Capacity (MW)	% Owned	Capacity Owned (MW)	2010 Capacity Factor (%)	Primary Fuel
		At December 31, 2010				
Calvert Cliffs Unit 1 (1)	Calvert Co., MD	855	50.0	428	90.0	Nuclear
Calvert Cliffs Unit 2 (1)	Calvert Co., MD	850	50.0	425	97.2	Nuclear
Nine Mile Point Unit 1 (1)	Scriba, NY	620	50.0	310	97.5	Nuclear
Nine Mile Point Unit 2 (1)	Scriba, NY	1,138	41.0	467	89.7	Nuclear
R.E. Ginna (1)	Ontario, NY	581	50.0	291	97.2	Nuclear
Brandon Shores	Anne Arundel Co., MD	1,273	100.0	1,273	54.1	Coal
H. A. Wagner	Anne Arundel Co., MD	976	100.0	976	19.2	Coal/Oil/Gas
C. P. Crane	Baltimore Co., MD	399	100.0	399	24.2	Oil/Coal
Keystone	Armstrong and Indiana Cos., PA	1,711	21.0	359(5)	90.4	Coal
Conemaugh	West Moreland Co., PA	1,711	10.6	181(5)	81.1	Coal
Perryman	Harford Co., MD	347	100.0	347	2.2	Oil/Gas
Riverside	Baltimore Co., MD	228	100.0	228	0.7	Oil/Gas
Handsome Lake	Rockland Twp, PA	268	100.0	268	2.7	Gas
Notch Cliff	Baltimore Co., MD	101	100.0	101	2.0	Gas
Westport	Baltimore City, MD	116	100.0	116	0.5	Gas
Gould Street	Baltimore City, MD	97	100.0	97	2.6	Gas
Philadelphia Road	Baltimore City, MD	61	100.0	61	0.5	Oil
Safe Harbor	Safe Harbor, PA	417	66.7	278	27.1	Hydro
Criterion	Oakland, MD	70	100.0	70	2.5	Wind
Grande Prairie	Alberta, Canada	93	100.0	93	8.4	Gas
West Valley	Salt Lake City, UT	200	100.0	200	10.6	Gas
Hillabee Energy Center	Alexander City, Alabama	740	100.0	740	36.8	Gas
Colorado Bend Energy Center	Wharton, Texas	550	100.0	550	17.0	Gas
Quail Run Energy Center (2)	Odessa, Texas	550	100.0	550	15.3	Gas
Panther Creek	Nesquehoning, PA	80	50.0	40	96.6	Waste Coal
Colver	Colver Township, PA	102	25.0	26	99.2	Waste Coal
Sunnyside	Sunnyside, UT	51	50.0	26	84.5	Waste Coal
ACE	Trona, CA	102	31.1	32	88.0	Coal
Jasmin	Kern Co., CA	35	50.0	18	87.7	Coal
POSO	Kern Co., CA	35	50.0	18	92.0	Coal
Rocklin	Placer Co., CA	24	50.0	12	80.6	Biomass
Fresno	Fresno, CA	24	50.0	12	83.6	Biomass
Chinese Station	Jamestown, CA	22	45.0	10	58.6	Biomass
Malacha	Muck Valley, CA	32	50.0	16	10.6	Hydro
Constellation Solar (6)	Various	9	100.0	9		Solar
SEGS IV	Kramer Junction, CA	33	12.2	4	27.1	Solar
SEGS V	Kramer Junction, CA	24	4.2	1	33.0	Solar
SEGS VI	Kramer Junction, CA	34	8.8	3	28.4	Solar

Total Generating Facilities (3)(4)	14,559	9,030

(1) *We own a 50.01% membership interest in CENG, the joint venture with EDF that holds these nuclear generating assets as a result of the sale of a 49.99% interest in CENG to EDF that was completed in November 2009. We discuss this transaction in more detail in Note 2 to Consolidated Financial Statements.*

(2) *On December 30, 2010, we signed an agreement to sell the Quail Run Energy Center to High Plains Diversified Energy Corporation (HPDEC) for $185.3 million. The agreement is contingent upon HPDEC obtaining financing through the sale of municipal bonds.*

(3) *The sum of the individual plant capacity megawatts may not equal the total due to the effects of rounding.*

(4) *Capacity figures represent summer seasonal claimed capacity amounts. For units with power purchase agreements, we use the contract capacity.*

(5) *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.*

(6) *Constellation Solar is our operation that constructs, owns, and operates solar facilities.*

In January 2011, we completed the acquisition of Boston Generating's 2,950MW nameplate capacity (2,656 MW of summer seasonal claimed capacity) fleet of generating plants: four natural gas-fired plants, including Mystic 8 and 9 (1,580 MW), Fore River (787 MW), and Mystic 7 (574 MW) as well as a fuel oil plant, Mystic Jet (9 MW). After this acquisition, our total summer seasonal claimed capacity owned increased to approximately 11,686 MW.

In December 2009, we were selected by the State of Maryland to develop an approximately 17 MW solar photovoltaic power installation in Emmitsburg, Maryland. This $60 million solar facility will be constructed, owned, operated and maintained by us. We expect the project to be completed by December 2012.

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As of December 31, 2010, we also have a 50% ownership interest in a waste coal processing facility located in Hazelton, Pennsylvania.

Item 3. Legal Proceedings

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

Item 4. [Removed and Reserved]

Executive Officers of the Registrant

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Mayo A. Shattuck III	56	Chairman of the Board (since July 2002), President and Chief Executive Officer (since November 2001) of Constellation Energy	Chairman of the Board of Baltimore Gas and Electric Company
Michael J. Wallace (1)	63	Vice Chairman (since March 2008), Executive Vice President (since January 2004) and Chief Operating Officer (since May 2009) of Constellation Energy	President and Chief Executive Officer Constellation Energy Nuclear Group, LLC
Henry B. Barron	60	Executive Vice President of Constellation Energy (since April 2008); and President and Chief Executive Officer (since September 2008) of Constellation Energy Nuclear Group	Chief Nuclear Officer of Constellation Energy Nuclear Group; and Group Executive and Chief Nuclear Officer Duke Energy
James L. Connaughton	49	Executive Vice President, Corporate Affairs, Public and Environmental Policy (since February 2009)	Chairman of the White House Council on Environmental Quality and Director of the White House Office of Environmental Policy
Paul J. Allen	59	Senior Vice President (since January 2004) and Chief Environmental Officer (since June 2007) of Constellation Energy	None
Charles A. Berardesco	52	Senior Vice President (since October 2008), General Counsel (since October 2008) and Corporate Secretary (since July 2004) of Constellation Energy	Vice President and Deputy General Counsel Constellation Energy; and Associate General Counsel Constellation Energy
Brenda L. Boultwood	46	Senior Vice President and Chief Risk Officer of Constellation Energy (since January 2008)	Global Head of Strategy and Global Head of Derivative Services, Alternative Investment Services and Head of Treasury Services Risk Management J.P. Morgan Chase & Company
Kenneth W. DeFontes, Jr.	60	Senior Vice President of Constellation Energy (since October 2004); and President and Chief Executive Officer of Baltimore Gas and Electric Company (since October 2004)	None
Andrew L. Good	43	Senior Vice President, Corporate Strategy and Development of Constellation Energy (since November 2009)	Senior Vice President and Chief Financial Officer Constellation Energy Resources; Senior Vice President and Chief Financial Officer Constellation Energy Commodities Group; and Senior Vice President, Finance Constellation Energy
Kathleen W. Hyle	52	Senior Vice President of Constellation Energy (since September 2005); and Chief Operating Officer of Constellation Energy Resources (since November 2008)	Senior Vice President, Finance, and Chief Financial Officer Constellation Energy Nuclear Group; Chief Financial Officer UniStar Nuclear Energy; Senior Vice President, Finance Constellation Energy; and Chief Financial Officer, Constellation NewEnergy
Mary L. Lauria	46	Senior Vice President and Chief Human Resources Officer of Constellation Energy (since October 2010)	Vice President and Chief Talent Officer Constellation Energy; Vice President, Talent Management and Leadership Development Wyeth; Director, Global Talent Management Johnson & Johnson
Jonathan W. Thayer	39	Senior Vice President and Chief Financial Officer of Constellation Energy (since October 2008)	Vice President and Managing Director, Corporate Strategy and Development Constellation Energy; Treasurer Constellation Energy; and Senior Vice President and Chief Financial Officer Baltimore Gas and Electric Company

(1)

Mr. Wallace will retire from Constellation Energy effective April 2011.

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 officer and any other person pursuant to which the officer was selected.

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PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters, Issuer Purchases of Equity Securities, and Unregistered Sales of Equity and Use of Proceeds

Stock Trading

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

As of January 31, 2011, there were 33,239 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, unless Constellation Energy elects to defer interest payments on the 8.625% Series A Junior Subordinated Debentures due June 15, 2063, and any deferred interest remains unpaid.

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 2011, we announced a quarterly dividend of $0.24 per share payable April 1, 2011 to holders of record at the close of business on March 10, 2011. This is equivalent to an annual rate of $0.96 per share.

Quarterly dividends were declared on our common stock during 2010 and 2009 in the amounts set forth below.

BGE pays dividends on its common stock after its Board of Directors declares them. However, pursuant to the order issued by the Maryland PSC on October 30, 2009 in connection with its approval of the transaction with EDF, BGE cannot pay common dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated under the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. There are no other 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

	2010			2009		
	Dividend Declared	Price High	Price Low	Dividend Declared	Price High	Price Low
First Quarter	$ 0.24	$ 36.99	$ 31.08	$ 0.24	$ 27.97	$ 15.05
Second Quarter	0.24	38.73	32.09	0.24	28.05	20.18
Third Quarter	0.24	35.10	28.21	0.24	33.37	25.76
Fourth Quarter	0.24	33.18	27.64	0.24	36.55	30.24
Total	$ 0.96			$ 0.96		

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

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

Period	Total Number of Shares Purchased (1)	Average Price Paid for Shares	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Amount of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)
October 1 - October 31, 2010	113	$ 32.34		
November 1 - November 30, 2010				
December 1 - December 31, 2010	92,643	30.84		
Total	92,756	$ 30.84		

(1) *Represents shares surrendered by employees to satisfy tax withholding obligations on vested restricted stock and restricted stock units.*

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Item 6. Selected Financial Data

Constellation Energy Group, Inc. and Subsidiaries

	2010	2009	2008	2007	2006
		(In millions, except per share amounts)			
Summary of Operations					
Total Revenues	**$ 14,340.0**	$ 15,598.8	$ 19,741.9	$ 21,185.1	$ 19,271.1
Total Expenses	**15,853.8**	14,588.5	20,821.9	19,858.8	18,025.2
Equity investment earnings (losses)	**25.0**	(6.1)	76.4	8.1	13.8
Gain on Sale of Interest in CENG		7,445.6			
Net Gain (Loss) on Divestitures	**245.8**	(468.8)	25.5		73.8
(Loss) Income From Operations	**(1,243.0)**	7,981.0	(978.1)	1,334.4	1,333.5
Gains on Sales of CEP LLC equity				63.3	28.7
Other (Expense) Income	**(76.7)**	(140.7)	(69.5)	157.4	66.8
Fixed Charges	**277.8**	350.1	349.1	292.4	315.5
(Loss) Income Before Income Taxes	**(1,597.5)**	7,490.2	(1,396.7)	1,262.7	1,113.5
Income Tax (Benefit) Expense	**(665.7)**	2,986.8	(78.3)	428.3	351.0
(Loss) Income from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles	**(931.8)**	4,503.4	(1,318.4)	834.4	762.5
(Loss) Income from Discontinued Operations, Net of Income Taxes				(0.9)	187.8
Net (Loss) Income	**$ (931.8)**	$ 4,503.4	$ (1,318.4)	$ 833.5	$ 950.3
Net Loss (Income) Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**50.8**	60.0	(4.0)	12.0	13.9
Net (Loss) Income Attributable to Common Stock	**$ (982.6)**	$ 4,443.4	$ (1,314.4)	$ 821.5	$ 936.4
(Loss) Earnings Per Common Share from Continuing Operations and Before Cumulative Effects of Changes in Accounting Principles Assuming Dilution	**$ (4.90)**	$ 22.19	$ (7.34)	$ 4.51	$ 4.12
(Loss) Income from Discontinued Operations				(0.01)	1.04
(Loss) Earnings Per Common Share Assuming Dilution	**$ (4.90)**	$ 22.19	$ (7.34)	$ 4.50	$ 5.16
Dividends Declared Per Common Share	**$ 0.96**	$ 0.96	$ 1.91	$ 1.74	$ 1.51
Summary of Financial Condition					
Total Assets	**$ 20,018.5**	$ 23,544.4	$ 22,284.1	$ 21,742.3	$ 21,801.6
Current Portion of Long-Term Debt	**$ 305.3**	$ 56.9	$ 2,591.5	$ 380.6	$ 878.8
Capitalization:					
Long-Term Debt	**$ 4,448.8**	$ 4,814.0	$ 5,098.7	$ 4,660.5	$ 4,222.3
Noncontrolling Interests	**88.8**	75.3	20.1	19.2	94.5
BGE Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholders' Equity	**7,829.2**	8,697.1	3,181.4	5,340.2	4,609.3

Total Capitalization	**$ 12,556.8**	$ 13,776.4	$ 8,490.2	$ 10,209.9	$ 9,116.1
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**N/A**	14.76	N/A	3.84	4.05
Book Value Per Share of Common Stock	**$ 39.19**	$ 43.27	$ 15.98	$ 29.93	$ 25.54

N/A Calculation is not applicable as a result of the net loss for 2010 and 2008.

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*.

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Baltimore Gas and Electric Company and Subsidiaries

	2010	2009	2008	2007	2006
			(In millions)		
Summary of Operations					
Total Revenues	**$ 3,461.7**	$ 3,579.0	$ 3,703.7	$ 3,418.5	$ 3,015.4
Total Expenses	**3,107.5**	3,310.6	3,521.2	3,084.2	2,646.3
Income From Operations	**354.2**	268.4	182.5	334.3	369.1
Other Income	**20.8**	25.4	29.6	26.9	6.0
Fixed Charges	**130.3**	139.3	139.9	125.3	102.6
Income Before Income Taxes	**244.7**	154.5	72.2	235.9	272.5
Income Taxes	**97.1**	63.8	20.7	96.0	102.2
Net Income	**147.6**	90.7	51.5	139.9	170.3
Preference Stock Dividends	**13.2**	13.2	13.2	13.2	13.2
Net Income Attributable to Common Stock before Noncontrolling Interests	**$ 134.4**	$ 77.5	$ 38.3	$ 126.7	$ 157.1
Net Loss (Income) Attributable to Noncontrolling Interests		7.3		(0.1)	
Net Income Attributable to Common Stock	**$ 134.4**	$ 84.8	$ 38.3	$ 126.6	$ 157.1
Summary of Financial Condition					
Total Assets	**$ 6,667.3**	$ 6,453.1	$ 6,086.2	$ 5,783.0	$ 5,140.7
Current Portion of Long-Term Debt	**$ 81.7**	$ 56.5	$ 90.0	$ 375.0	$ 258.3
Capitalization					
Long-Term Debt	**$ 2,059.9**	$ 2,141.4	$ 2,197.7	$ 1,862.5	$ 1,480.5
Noncontrolling Interest		17.6	16.9	16.8	16.7
Preference Stock Not Subject to Mandatory Redemption	**190.0**	190.0	190.0	190.0	190.0
Common Shareholder's Equity	**2,073.2**	1,938.8	1,538.2	1,671.7	1,651.5
Total Capitalization	**$ 4,323.1**	$ 4,287.8	$ 3,942.8	$ 3,741.0	$ 3,338.7
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**2.80**	2.07	1.50	2.84	3.60
Ratio of Earnings to Fixed Charges and Preferred and Preference Stock Dividends	**2.41**	1.80	1.33	2.42	2.99

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

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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 and joint ventures organized around three business segments: a generation business (Generation), a customer supply business (NewEnergy), and Baltimore Gas and Electric Company (BGE). We describe our operating segments in *Note 3 to Consolidated Financial Statements.*

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 of 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 sources of cash for future capital expenditures,
- our net available liquidity and collateral requirements, and
- expected future expenditures for capital projects.

As you read this discussion and analysis, refer to our Consolidated Statements of Income (Loss), which present the results of our operations for 2010, 2009, and 2008. We analyze and explain the differences between periods in the specific line items of our Consolidated Statements of Income (Loss).

We have organized our discussion and analysis as follows:

- First, we discuss our strategy.
- Then, we describe the business environment in which we operate including how recent events, 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 review our results of operations beginning with an overview of our total company results, followed by a more detailed review of those results by operating segment.

We review our financial condition addressing our sources and uses of cash, security ratings, capital resources, capital requirements, commitments, and off-balance sheet arrangements.

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

Strategy

Our strategy is to provide innovative and risk-mitigating energy products and solutions to North American wholesale and retail customers. Overall, we strive to serve our customers with diverse products and solutions to meet their energy needs.

In executing this strategy, we leverage our core strengths of:

maintaining and growing strong and diverse supply relationships with retail and wholesale customers,

owning, developing, operating, and contracting for generation assets,

integrating our expertise in managing physical and financial risks, and

providing reliable, regulated utility service to customers.

Our NewEnergy business focuses on sales of electricity, natural gas, and related products to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. The retail NewEnergy customer supply operation combines a unified sales force with a customer-centric model that leverages technology to broaden the range of products and services we offer, which we believe promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which we believe will provide a platform that is scalable and able to capitalize on opportunities for future growth.

NewEnergy obtains energy from both owned and contracted supply resources and actively manages these physical and contractual assets in order to derive incremental value. Additionally, NewEnergy is involved in the development, exploration and exploitation of natural gas properties.

Our Generation business has a fleet of plants that is strategically located in markets that support our customer-facing business and includes various fuel types, such as coal, natural gas, oil, nuclear, and renewable sources. We generally have load obligations greater than our generation output. Going forward, we intend to invest in generation assets in the markets where we serve load to provide a more efficient and balanced profile between our generation production and our customer load obligations.

Our strategy is enabled by a fleet of generation facilities and our risk management capabilities. This combination of our Generation and NewEnergy businesses also allows us to operate in a manner so we can minimize our collateral requirements. We discuss our collateral requirements in the *Collateral* section.

BGE, our regulated utility located in central Maryland, provides standard offer service and distributes electricity and gas to customers. BGE is also focusing on enhancing reliability and customer satisfaction, and is implementing customer demand response initiatives, including a comprehensive smart grid initiative and a full portfolio of conservation programs.

The ability of energy consumers to choose their supplier, regulatory change, and energy market conditions significantly impact our business. In response, we regularly evaluate our strategies to improve our competitive position. We actively anticipate and adapt to the business environment and regulatory changes that impact our industry. We are committed to maintaining a strong balance sheet and investment-grade credit

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quality by making disciplined investment and capital management decisions to support our strategic initiatives in an efficient and effective manner.

Business Environment

Various factors affect our financial results. We discuss some of these factors in more detail in *Item 1. Business Competition* section. We also discuss these various factors in the *Forward Looking Statements* and *Item 1A. Risk Factors* sections.

Throughout 2008, volatility in the financial markets intensified, leading to dramatic declines in equity and commodity prices and substantially reduced liquidity in the credit markets. Most equity indices declined significantly, the cost of credit default swaps and bond spreads increased substantially, and credit markets effectively ceased to be accessible for all but the most highly rated borrowers. In 2009 and 2010, markets in which we operate were affected by declining prices for power, gas, and capacity. We discuss the impact of declining commodity prices on our future earnings in more detail in the *Generation Results* section.

During 2009 and 2010, we improved our liquidity and reduced our business risk in response to these market events. We discuss our liquidity and collateral requirements in the *Financial Condition* section. We continue to actively manage our credit risk 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 *Risk Management* section.

Competition also impacts our business. We discuss competition in more detail in *Item 1. Business Competition* section.

The impacts of electric competition on BGE in Maryland are discussed in *Item 1. Business Baltimore Gas and Electric Company Electric Business Electric Competition* section.

Regulation Maryland

Maryland PSC

In addition to competition, which we discuss in *Item 1. Business Baltimore Gas and Electric Company Electric Business Electric 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 shown on customer billings as separate components for delivery service (i.e. base rates), electric supply (commodity charge and transmission), and certain taxes and surcharges. The rates for BGE's regulated gas business continue to consist of a delivery charge (base rates as well as certain taxes and surcharges) and a commodity charge.

Purchase of Supplier Receivables

Effective July 15, 2010, BGE, pursuant to Maryland PSC requirements, began to purchase receivables at a discount from third party competitive energy suppliers that provide our customers electricity and/or gas. The discount rate applied to the receivables is a regulated rate which is intended to cover BGE's costs associated with purchasing these receivables, such as uncollectibles, and is subject to an annual true-up to reflect actual costs.

Order Approving Membership Interest Sale in CENG to EDF

In October 2009, the Maryland PSC issued an order approving the sale of a 49.99% membership interest in CENG to EDF subject to the following conditions, with which both Constellation Energy and EDF complied or are complying:

- Constellation Energy funded a one-time, $100 per customer distribution rate credit for BGE residential customers totaling $112.4 million in the fourth quarter of 2009. Constellation Energy made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as ordered by the Maryland PSC.

Constellation Energy was required to make a $250 million cash capital contribution to BGE by no later than June 30, 2010. Constellation Energy made this equity contribution to BGE in December 2009.

BGE will not pay common dividends to Constellation Energy if:

- after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC's ratemaking precedents, or

- BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade.

BGE was prohibited from filing an electric and/or gas distribution rate case at any time prior to January 2010 and was ordered not to file a subsequent electric and/or gas distribution rate case until January 2011. Any rate increase in the first electric distribution rate case was capped at 5% as agreed to by Constellation Energy in its 2008 settlement with the State of Maryland and the Maryland PSC. In May 2010, BGE filed an electric and gas distribution rate case with the Maryland PSC and the Maryland PSC issued its order on the case in December 2010. We discuss this matter further in the *Base Rates* section below.

Constellation Energy is limited to allocating no more than 31% of its holding company costs to BGE until the Maryland PSC reviews such cost allocations in the context of BGE's next rate case.

Constellation Energy and BGE implemented "ring fencing" measures in February 2010 designed to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. Such measures include the formation of a new special purpose subsidiary by Constellation Energy to hold all of the common equity interests in BGE.

Maryland Settlement Agreement

In March 2008, Constellation Energy, BGE, and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC and certain State of

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Maryland officials to resolve pending litigation and to settle other prior legal, regulatory, and legislative issues. On April 24, 2008, the Governor of Maryland signed enabling legislation, which became effective on June 1, 2008. Pursuant to the terms of the settlement agreement:

- Each party acknowledged that the agreements adopted in 1999 relating to Maryland's electric restructuring law are final and binding and the Maryland PSC closed ongoing proceedings relating to the 1999 settlement.

- BGE provided its residential electric customers approximately $189 million in the form of a one-time $170 per customer rate credit. We recorded a reduction to "Electric revenues" on our and BGE's Consolidated Statements of Income (Loss) during the second quarter of 2008 and reduced customers' bills by the amount of the credit between September and December 2008.

- BGE customers were relieved of the potential future liability for decommissioning Calvert Cliffs Unit 1 and Unit 2, scheduled to begin no earlier than 2034 and 2036, respectively, and are no longer obligated to pay a total of $520 million, in 1993 dollars adjusted for inflation, pursuant to the 1999 Maryland PSC order regarding the deregulation of electric generation. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Maryland Senate Bill 1, which was enacted in June 2006.

- BGE resumed collection of the residential return portion of the administrative charge included in Standard Offer Service (SOS) rates, which had been eliminated under Senate Bill 1, on June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. This totaled $37.3 million over this period. Starting June 1, 2010, BGE has provided all residential electric customers a credit for the residential return component of the administrative charge. This credit will be given to customers through December 31, 2016.

- Any increase in electric distribution revenue awarded in the first electric distribution rate case filed by BGE after the settlement was capped at 5% with certain exceptions. The agreement does not govern or affect BGE's ability to recover costs associated with gas rates, federally approved transmission rates and charges, electric riders, tax increases, or increases associated with standard offer service power supply auctions.

- Effective June 1, 2008, BGE implemented revised depreciation rates for regulatory and financial reporting purposes. The revised rates reduced depreciation expense by approximately $14 million in 2008 and $25.2 million in 2009 without impacting distribution rates charged to customers.

- Effective June 1, 2008, Maryland laws governing investments in companies that own and operate regulated gas and electric utilities were amended to make them less restrictive with respect to certain capital stock acquisition transactions.

- Constellation Energy elected two independent directors to the Board of Directors of BGE within the required six months from the execution of the settlement agreement.

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.

BGE may ask the Maryland PSC to increase base rates from time to time, subject to limitations in the Maryland PSC's October 2009 order approving our transaction with EDF. 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.

In May 2010, BGE filed an application for an increase in its electric and gas base rates with the Maryland PSC. In August 2010, BGE updated its application to request an increase of $47.2 million and $30.4 million in its electric and gas base rates, respectively. The request was based upon an 8.99% rate of return with an 11.65% return on equity and a 52% equity ratio. While BGE demonstrated the need for a $92.3 million increase in electric base rates, distribution revenues awarded to BGE in the case were subject to a 5% cap pursuant to the terms of the 2008 settlement agreement with the State of Maryland as well as the Maryland PSC's order approving the EDF transaction.

On December 6, 2010, the Maryland PSC issued an abbreviated order authorizing BGE to increase electric distribution rates by no more than $31.0 million and increase gas distribution rates by no more than $9.8 million for service rendered on or after December 4, 2010. The electric distribution rate increase was based upon an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio. The gas distribution rate increase was based upon a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio. BGE implemented the abbreviated order, will evaluate the comprehensive rate order that the Maryland PSC will issue in the near future and will assess its alternatives. BGE cannot predict the outcome of this assessment.

Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at

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Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings. We have a similar revenue decoupling mechanism in our gas business.

Demand Response and Advanced Metering Programs

BGE defers costs associated with its demand response programs as a regulatory asset and recovers these costs from customers in future periods.

In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of approximately $480 million. The Maryland PSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is delivered to customers. Under a grant from the United States Department of Energy (DOE) BGE is a recipient of $200 million in federal funding for its smart grid and other related initiatives. This grant allows BGE to be reimbursed for smart grid and other expenditures up to $200 million, substantially reducing the total cost of these initiatives.

We discuss BGE's electric load management programs in more detail in *Item 1. Business Baltimore Gas and Electric Company Electric Load Management*. We discuss the associated regulatory assets in *Note 6 to Consolidated Financial Statements.*

Electric Standard Offer Service

BGE is obligated by the Maryland PSC to provide market-based standard offer service (SOS) to all of its electric customers who elect not to select a competitive energy supplier. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a shareholder return component and an incremental cost component. However, BGE is required under the terms of Senate Bill 1 to provide all residential electric customers a credit for the residential return component of the administrative fee. This credit will be given to customers through December 31, 2016. Currently, BGE is involved in a Maryland PSC proceeding to determine the future, on-going structure of the SOS administrative fee charged to all SOS customers.

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* section and in *Note 6 to Consolidated Financial Statements.*

Potential Reliability and Quality of Service Standards

The State of Maryland is considering legislative and regulatory changes that would impose new reliability and quality of service standards on electric and gas companies, as well as penalties for failure to meet those standards. We cannot at this time predict the final outcome of this process or how such outcome may affect our, or BGE's, financial results.

Federal Regulation

FERC

The FERC has jurisdiction over various aspects of our business, including electric transmission and wholesale natural gas and electricity sales. BGE transmission rates are updated annually based on a formula methodology approved by FERC. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007. We believe that FERC's continued commitment to fair and efficient wholesale energy markets should continue to result in improvements to competitive markets across various regions.

Since 1997, operation of BGE's transmission system has been under the authority of PJM Interconnection (PJM), the Regional Transmission Organization (RTO) for the Mid-Atlantic region, pursuant to FERC oversight. As the transmission operator, PJM administers 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, Texas, and New England. Similar to PJM, these RTOs also administer the energy market for their region and are responsible for operation of the transmission system and transmission system reliability. Our Generation and NewEnergy businesses participate in these regional energy markets. These markets are continuing to develop, and revisions to market structure are subject to review and approval by FERC. We cannot predict the outcome of any reviews at this time. However, changes to the structure of these markets could have a material effect on our financial results.

FERC Initiatives

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

In November 2004, FERC eliminated through and out transmission rates between the Midwest Independent System Operator (MISO) and PJM and put in place Seams Elimination Charge/Cost Adjustment/Assignment (SECA) transition rates, which are paid by the transmission customers of MISO and

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PJM and allocated among the various transmission owners in PJM and MISO. The SECA transition rates were in effect from December 1, 2004 through March 31, 2006. FERC set for hearing the various compliance filings that established the level of the SECA rates and has indicated that the SECA rates are being recovered from the MISO and PJM transmission customers subject to refund by the MISO and PJM transmission owners.

We are a recipient of SECA payments, payer of SECA charges, and supplier to whom such charges may be shifted. Administrative hearings regarding the SECA charges concluded in May 2006, and an initial decision from the FERC administrative law judge (ALJ) was issued in August 2006. The decision of the ALJ generally found in favor of reducing the overall SECA liability. In May 2010, FERC issued an order approving in part and reversing in part the ALJ decision. The FERC order results in additional SECA liabilities being imposed on us. In June 2010, we filed a request for rehearing of the FERC order on the ALJ decision, as did other interested parties. The rehearing requests are pending at FERC. In July 2010, BGE filed a petition for review of FERC's approval of the SECA methodology, and this appeal is being held in abeyance pending action by FERC on the pending rehearing requests. In the interim, PJM and MISO have made filings at FERC to comply with the May 2010 decision and to impose charges accordingly. Depending on the ultimate outcome, the proceeding may have a material effect on our financial results.

Capacity Markets

In general, capacity market design revisions are routinely proposed and considered on an ongoing basis. Such changes are subject to FERC's review and approval. Currently, we cannot predict the outcome of these proceedings or the possible effect on our, or BGE's, financial results.

Through 2008 and 2009, PJM made several filings at FERC proposing various revisions to its capacity market, or Reliability Pricing Model (RPM), including the determination of the cost-of-new-entry (CONE), which is an important component in determining the price paid to capacity resources in PJM. PJM also proposed revisions relating to the participation of energy efficiency and demand resources, and market power and mitigation rules. Some of these matters are still pending at FERC. While recent RPM design changes have not yet had a material effect on our financial results, we cannot predict the outcome of the issues still pending or on any capacity market design changes that result from new regulatory requirements. Such changes could have a material impact on our financial results.

In May 2008, five state public service commissions, including the Maryland PSC, consumer advocates, and others filed a complaint against PJM at the FERC, alleging that the RPM produced unreasonable prices during the period from June 1, 2008 through May 31, 2011. The complaint requested that FERC establish a refund effective date of June 1, 2008, reject the results of the 2007/08 through 2010/11 RPM capacity auction results, and significantly reduce prices for capacity beginning as of June 1, 2008 through 2011/12. FERC dismissed the complaint and denied rehearing, and ultimately the Maryland PSC and New Jersey Board of Public Utilities appealed the case to the United States Court of Appeals for the District of Columbia. In February 2011, the court denied the petition for review and held that FERC adequately explained why the RPM auction structure was just and reasonable. The petitioners could seek to appeal the court's decision to the United States Supreme Court. We cannot predict at this time whether the petitioners will seek an appeal or the outcome of any further proceedings.

In April 2009, the Attorney General of Connecticut, the Connecticut Department of Public Utilities and Office of Consumer Counsel (together, the Connecticut Parties) filed complaints at FERC alleging improper energy bidding behavior since December 1, 2006 by generators located in New York that also received capacity payments within ISO-New England. In May 2009, the Connecticut Parties filed an amended complaint asserting that Constellation Energy Commodities Group, Inc. (CCG) and others received capacity payments while never intending to perform as capacity resources. The revised allegations assert that certain generators engaged in "economic withholding" by submitting energy bids at or near the offer cap. Since December 2006, CCG has received approximately $7 million in payments for capacity offered into ISO-New England associated with Constellation Energy's previously wholly owned nuclear facilities located in NY. In August 2009, FERC issued an order setting this matter for a public hearing before an ALJ to determine the intent of the capacity suppliers (including CCG) in making their energy offers in ISO-New England. CCG actively participated in the proceeding, and in September 2010 the ALJ issued an Initial Decision finding that the Connecticut Parties failed to prove their case and dismissed the complaint against CCG. The Initial Decision is pending before FERC for approval or modification.

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

In addition to legal challenges to capacity markets and regulatory advocacy before FERC seeking to revise the capacity market structures, states are seeking more direct ways to affect the results of wholesale capacity markets. In January 2011, the New Jersey legislature adopted legislation that would provide for guaranteed cost recovery for the development of up to 2,000 MWs of new base load or mid-merit generation in exchange for the requirement that the new generation clear in the PJM capacity market. Similarly, the Maryland PSC issued a draft Request for Proposals that, subject to an evidentiary hearing confirming the reliability need for such resources, contemplates having Maryland ratepayers fund the development of new generation and to require that eligible new generation clear in the PJM capacity market. Such state efforts are intended to depress capacity prices, and are subject to legal and regulatory challenge. Depending on the outcome of these challenges, these state efforts could have a material effect on our financial results.

NERC Reliability Standards

In compliance with the Energy Policy Act of 2005, FERC has approved the North American Electric Reliability Corporation (NERC) as the national energy reliability organization. NERC will be responsible for the development and enforcement of mandatory reliability and cyber-security standards for the wholesale electric power system. We are responsible for complying with the standards in the regions in which we operate. NERC will have the ability to assess financial penalties for noncompliance, which could be material.

Concerns over the security of the country's energy infrastructure could lead to additional future rules or regulations related to the operation and security requirements of our generating facilities and electric and gas transmission and distribution systems, which could have a material impact on our operations and financial results.

Financial Regulatory Reform

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in our industry to hedge their risks, which we believe results in the new derivatives requirements not being applicable to us for most of our activities. However, there will be several key rulemakings to implement the derivatives requirements, which, depending on the final scope of the regulations, could attempt to impose significant obligations on us nonetheless. Final regulations may address collateral requirements and exchange margin cash postings, which if applicable to us despite being an end user of derivatives, could have the effect of increasing collateral requirements or the amount of exchange margin cash postings in lieu of letters of credit currently issued on over-the-counter contracts. These regulations could also result in additional transactional and compliance costs to the extent they apply to us, and could impact market liquidity.

In addition to new regulation over derivatives, the Dodd-Frank Act amends the Sarbanes-Oxley Act to permanently exempt nonaccelerated filers, including BGE, from the requirement to obtain an audit report on internal controls over financial reporting.

Market Oversight

Regulatory agencies that have jurisdiction over our businesses, including the FERC and Commodity Future Trading Commission (CFTC), possess broad enforcement and investigative authority to ensure well functioning markets and to prohibit market manipulation or violations of the agencies' rules or orders. These agencies also possess significant civil penalty authority, including in the case of FERC and the CFTC, the authority to impose a penalty of up to $1 million per day per violation. We are committed to a culture of compliance and ensuring compliance with all applicable rules, laws and orders. Nonetheless, the regulatory agencies engage in either public or non-public investigations in response to allegations of wrongdoing and we may be involved in certain market activities that become subject to investigations. Even where no wrongdoing is found, the process of participating in a regulatory investigation could have a material effect on our business.

Weather

Generation and NewEnergy Businesses

Weather conditions in the different regions of North America influence the financial results of our Generation and NewEnergy businesses. Weather conditions can affect the supply of and demand for electricity, natural gas, and fuels. Changes in energy supply and demand may impact the price of these energy commodities in both the spot market and the forward market, which may affect our results in any given period. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. The demand for and price of natural gas and oil are higher in the winter. However, all regions of North America typically do not experience extreme weather conditions at the same time, thus we are not typically exposed to the effects of extreme weather in all parts of our business at once.

BGE

Weather affects the demand for electricity and gas for our regulated businesses. Very hot summers and very cold winters increase demand. Mild weather reduces demand. Weather affects residential sales more than commercial and industrial sales, which are mostly affected by business needs for electricity and gas. The Maryland PSC has approved revenue decoupling mechanisms which allow BGE to record monthly adjustments to the majority of our regulated electric and gas business distribution revenues to eliminate the effect of abnormal weather and usage patterns. We discuss this further in the *Regulation Maryland Revenue Decoupling, Regulated Electric Business Revenue Decoupling* and *Regulated Gas Business Revenue Decoupling* sections.

Other Factors

A number of other factors significantly influence the level and volatility of prices for energy commodities and related derivative products for our NewEnergy 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,

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- 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,
- state and local environmental regulations,
- local transportation systems, and
- the nature and extent of electricity competition.

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 to Consolidated Financial Statements* and *Item 1. Business Environmental Matters* section. We discuss details of our legal proceedings in *Note 12 to Consolidated Financial Statements*. 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 to Consolidated Financial Statements*.

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 (Loss),
- 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 accounting policies discussed below 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 to Consolidated Financial Statements*.

Accounting for Derivatives and Hedging Activities

We utilize a variety of derivative instruments in order to manage commodity price risk, interest rate risk, and foreign currency risk. Because of the extensive nature of the accounting requirements that govern both accounting treatment and documentation, as well as the complexity of the transactions within the scope of these requirements, management is required to exercise judgment in several areas, including the following:

- identification of derivatives,
- selection of accounting treatment for derivatives,
- valuation of derivatives, and
- impact of uncertainty.

As discussed in more detail below, the exercise of management's judgment in these areas materially impacts our financial statements. While we believe we have appropriate controls in place to apply the derivative accounting requirements, failure to meet these requirements, even inadvertently, could require the use of a different accounting treatment for the affected transactions. In addition, interpretations of these accounting requirements continue to evolve, and future changes in accounting requirements also could affect our financial statements materially. We discuss derivatives and hedging activities in more detail in *Note 1* and *Note 13 to Consolidated Financial Statements*.

Identification of Derivatives

We must evaluate new and existing transactions and agreements to determine whether they are derivatives or if they contain embedded derivatives. Identifying derivatives requires us to exercise judgment in interpreting the definition of a derivative and applying that definition to each individual contract. If a contract is not a derivative, we cannot apply derivative accounting, and we generally must record the effects of the contract in our financial statements upon delivery or settlement under the accrual method of accounting. In contrast, if a contract is a derivative, we must apply derivative accounting,

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which provides for several possible accounting treatments as discussed more fully under *Accounting Treatment* below. As a result, the required accounting treatment and its impact on our financial statements can vary substantially depending upon whether a contract is a derivative or a non-derivative.

Accounting Treatment

We are permitted several possible accounting treatments for derivatives that meet all of the applicable requirements. Mark-to-market is the default accounting treatment for all derivatives unless they qualify, and we affirmatively designate them, for one of the other accounting treatments. Derivatives designated for any of the other elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

The permissible accounting treatments for derivatives are:

- mark-to-market,
- cash flow hedge,
- fair value hedge, and
- accrual accounting under Normal Purchase/Normal Sale (NPNS).

Each of the accounting treatments that we use for derivatives affects our financial statements in substantially different ways as summarized below:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Mark-to-market	Derivative asset or liability recorded at fair value	Changes in fair value recognized in earnings
Cash flow hedge	Derivative asset or liability recorded at fair value	Ineffective changes in fair value recognized in earnings
	Effective changes in fair value recognized in accumulated other comprehensive income	Amounts in accumulated other comprehensive income reclassified to earnings when the hedged forecasted transaction affects earnings or becomes probable of not occurring
Fair value hedge	Derivative asset or liability recorded at fair value	Changes in fair value recognized in earnings
	Book value of hedged asset or liability adjusted for changes in its fair value	Changes in fair value of hedged asset or liability recognized in earnings
NPNS (accrual)	Fair value not recorded	Changes in fair value not recognized in earnings
	Accounts receivable or accounts payable recorded when derivative settles	Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

We exercise judgment in determining which derivatives qualify for a particular accounting treatment, including:

- Cash flow and fair value hedges determination that all hedge accounting requirements are satisfied, including the expectation that the derivative will be highly effective in offsetting changes in cash flows or fair value from the risk being hedged and, for cash flow hedges, the probability that the hedged forecasted transaction will occur.
- Accrual accounting under NPNS determination that the derivative will result in gross physical delivery of the underlying commodity and will not settle on a net basis.

We also exercise judgment in selecting the accounting treatment that we believe provides the most transparent presentation of the economics of the underlying transactions. Although contracts may be eligible for hedge accounting or NPNS designation, we are not required to designate and account for all such contracts identically. We generally elect NPNS accrual or hedge accounting for our physical energy delivery activities because accrual accounting more closely aligns the timing of earnings recognition, cash flows, and the underlying business activities. By contrast, we generally apply mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity. However, we also use mark-to-market accounting for the following activities:

- our competitive retail gas customer supply activities and our fixed quantity competitive retail power customer supply activities for new transactions closed after June 30, 2010, which are managed using economic hedges that we have not designated as cash-flow hedges so as to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible,
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting, and
- interest rate swaps related to our debt if they do not qualify as fair value hedges.

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As a result of making these judgments, the selection of accounting treatments for derivatives has a material impact on our financial position and results of operations. These impacts affect several components of our financial statements, including assets, liabilities, and accumulated other comprehensive income (AOCI). Additionally, the selection of accounting treatment also affects the amount and timing of the recognition of earnings. The following table summarizes these impacts:

Effect of Changes in Fair Value on:	Accounting Treatment			
	Mark-to-market	**Cash Flow Hedge**	**Fair Value Hedge**	**NPNS**
Assets and liabilities	Increase or decrease in derivatives	Increase or decrease in derivatives	Increase or decrease in derivatives Decrease or increase in hedged asset or liability	No impact
AOCI	No impact	Increase or decrease for effective portion of hedge	No impact	No impact
Earnings prior to settlement	Increase or decrease	Increase or decrease for ineffective portion of hedge	Increase or decrease for change in derivatives Decrease or increase for change in hedged asset or liability Increase or decrease for ineffective portion	No impact
Earnings at settlement	No impact	Amounts in AOCI reclassified to earnings when hedged forecasted transaction affects earnings or when the forecasted transaction becomes probable of not occurring	Hedged margin recognized in earnings	Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

Valuation

We record mark-to-market and hedge derivatives at fair value, which represents an exit price for the asset or liability from the perspective of a market participant. An exit price is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. While some of our derivatives relate to commodities or instruments for which quoted market prices are available from external sources, many other commodities and related contracts are not actively traded. Additionally, some contracts include quantities and other factors that vary over time. In these cases, we must use modeling techniques to estimate expected future market prices, contract quantities, or both in order to determine fair value.

The prices, quantities, and other factors we use to determine fair value reflect management's best estimates of inputs a market participant would consider. We record valuation adjustments to reflect uncertainties associated with estimates inherent in the determination of fair value that are not incorporated in market price information or other market-based estimates we use to determine fair value. 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 discuss fair value measurements in more detail in *Note 13 to Consolidated Financial Statements*.

The judgments we are required to make in order to estimate fair value have a material impact on our financial statements. These judgments affect the selection, appropriateness, and application of modeling techniques, the methods used to identify or estimate inputs to the modeling techniques, and the consistency in applying these techniques over time and across types of derivative instruments. Changes in one or more of these judgments could have a material impact on the valuation of derivatives and, as a result, could also have a material impact on our financial position or results of operations.

Impacts of Uncertainty

The accounting for derivatives and hedging activities involves significant judgment and requires the use of estimates that are inherently uncertain and may change in subsequent periods. The effect of changes in assumptions and estimates could materially impact our reported amounts of revenues and costs and could be affected by many factors including, but not limited to, the following:

- uncertainty surrounding inputs to the estimates of fair value due to factors such as illiquid markets or the absence of observable market price information,
- our ability to continue to designate and qualify derivative contracts for NPNS accounting or hedge accounting,

- potential volatility in earnings from ineffectiveness on derivatives for which we have elected hedge accounting, and
- our ability to enter into new mark-to-market derivative origination transactions.

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. We are required to test our long-lived assets for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes are:

- a significant decrease in the market price of a long-lived asset,
- a significant adverse change in the manner an asset is being used or its physical condition,
- an adverse action by a regulator or legislature or an adverse change in the business climate,
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,
- a current period loss combined with a history of losses or the projection of future losses, or
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

For long-lived assets classified as held for sale, we recognize an impairment loss to the extent their carrying amount exceeds their fair value less costs to sell. For long-lived assets that we expect to hold and use, we recognize an impairment loss only if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable if it exceeds the total 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 estimate the undiscounted future cash flows associated with the asset at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. This necessarily requires us to estimate uncertain future cash flows.

In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our 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.

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 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.

Unproved Gas Properties

We evaluate unproved property at least annually to determine if it is impaired. Impairment for unproved property occurs if there are no firm plans to continue drilling, the lease is near its expiration, or historical experience necessitates a valuation allowance. The determination of whether to continue to develop the lease is based upon the economics (forward prices and the level of gas reserves) associated with extracting the estimated gas reserves, which necessarily involves the exercise of judgment.

Investments

We evaluate our equity method and cost method investments (for example, CENG, UNE (through November 3, 2010), and partnerships that own power projects) to determine whether or not they are impaired. The standard for determining whether an impairment must be recorded is whether the investment has experienced an "other than a temporary" decline in value.

The evaluation and measurement of investment impairments involves the same uncertainties as described above for long-lived assets that we own directly. 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, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value.

We continuously monitor issues that potentially could impact future profitability of our equity method investments that own coal, hydroelectric, fuel processing projects, as well as our equity investment in our nuclear joint venture. These issues include 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.

California statutes and regulations require load-serving entities to increase their procurement of renewable energy

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resources and mandate statewide reductions in greenhouse gas emissions. Given the need for electric power and the statutory and regulatory requirements increasing demand for renewable resource technologies, we believe California will continue to foster an environment that supports the use of renewable energy and continues certain subsidies that will make renewable energy projects economical. However, should California legislation and regulatory policies and federal energy policies fail to adequately support renewable energy initiatives, our equity method investments in these types of projects could become impaired, and any losses recognized could be material.

Goodwill

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We do not amortize goodwill. We 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.

Significant Events

Comprehensive Agreement with EDF

In October 2010, we reached a comprehensive agreement with EDF Group and related entities (EDF) that restructured the relationship between our two companies, eliminated the outstanding asset put arrangement, and transferred to EDF the full ownership of UniStar Nuclear Energy, LLC (UNE). We completed the sale of our 50% membership interest in UNE in November 2010. We discuss the terms of the comprehensive agreement in *Note 4 to Consolidated Financial Statements.*

Acquisitions

Criterion Wind Project

In April 2010, we acquired the Criterion wind project to be constructed in Garrett County, Maryland. We have completed construction and placed the 70 MW project in service in December 2010.

Texas Combined Cycle Generation Facilities

In May 2010, we acquired the 550 MW Colorado Bend Energy Center and the 550 MW Quail Run Energy Center natural gas combined cycle generation facilities in Texas for $372.9 million.

Hillabee Energy Center

In June 2010, the Hillabee Energy Center, a 740 MW gas-fired combined cycle power generation facility located in Alabama, began commercial dispatch. We had acquired this under construction facility in 2008.

CPower

In October 2010, we acquired CPower, an energy management and demand response provider, for approximately $78 million, subject to closing adjustments.

Boston Generating

In January 2011, we completed the acquisition of Boston Generating's 2,950 MW fleet of generating plants for approximately $1.1 billion, subject to a working capital true-up adjustment. The fleet acquired includes the following four natural gas-fired power plants and one fuel oil plant located in the Boston, Massachusetts area:

- Mystic 7   574 MW,

Mystic 8 and 9 1,580 MW,

Fore River 787 MW, and

Mystic Jet, a fuel oil plant 9 MW.

We discuss these transactions in more detail in *Note 15 to Consolidated Financial Statements.*

Divestitures

In January 2010, BGE completed the sale of its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party.

In August 2010, we completed the sale of our interests in the Mammoth Lakes geothermal generating facility.

In November 2010, we closed on our comprehensive agreement with EDF in which we sold our interest in UNE.

In December 2010, we signed an agreement to sell our Quail Run Energy Center, a 550 MW natural gas plant in west Texas, to High Plains Diversified Energy Corporation (HPDEC) for $185.3 million. This agreement is contingent upon HPDEC obtaining financing through the sale of municipal bonds.

We discuss these transactions in more detail in *Note 2 to Consolidated Financial Statements.*

Impairment Losses and Other Costs

During 2010, we recorded impairment losses on our investments in CENG and UNE and certain of our other equity method investments. We discuss these charges in more detail in *Note 2 to Consolidated Financial Statements*.

International Coal Contract Dispute Settlement

During 2010, we finalized the settlement of a contract dispute with a third party international coal supplier for a net pre-tax gain of $56.6 million. We discuss this settlement in *Note 2 to Consolidated Financial Statements*.

Financing Activities

Issuance of Notes

In December 2010, we issued $550 million of 5.15% Notes due December 1, 2020.

Redemption of Notes

In February 2010, we redeemed certain of our 7.00% Notes due April 1, 2012 as part of a cash tender offer launched in January 2010 and in March 2010 we repurchased certain tax exempt notes.

In December 2010, we issued a call notice to redeem $213.5 million, which represents the remaining outstanding 7.00% Notes due April 1, 2012. We redeemed these notes in January 2011.

We discuss these financing transactions in more detail *Note 9 to Consolidated Financial Statements*.

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Healthcare Reform Legislation

In March 2010, the Patient Protection and Affordable Care Act and the Healthcare and Education Reconciliation Act of 2010 (Reconciliation Act) were signed into law. We discuss the impact of these new laws on our earnings in more detail in *Note 2 to Consolidated Financial Statements*.

Results of Operations

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

As discussed in *Item 1 Business Overview* section and in the *Strategy* and *Significant Events* sections, Constellation Energy's 2010, 2009 and 2008 operating results were materially impacted by a number of significant events, transactions, and changes in our strategic direction. The impact of these items has affected the comparability of our 2010, 2009 and 2008 results to prior periods and will alter Constellation Energy's operating results in the future. In this section, we highlight the 2010, 2009 and 2008 impacts of these items.

Overview

Results

	2010	2009	2008
		(In millions, after-tax)	
Net (Loss) Income:			
Generation	**$ (1,255.3)**	$ 4,766.7	$ (357.7)
NewEnergy	**176.2**	(348.2)	(1,011.4)
Regulated electric	**110.0**	79.1	11.1
Regulated gas	**37.6**	25.5	40.4
Other nonregulated	**(0.3)**	(19.7)	(0.8)
Net (Loss) Income	**$ (931.8)**	$ 4,503.4	$ (1,318.4)
Net (Loss) Income attributable to common stock	**$ (982.6)**	$ 4,443.4	$ (1,314.4)
Change from prior year	**$ (5,426.0)**	$ 5,757.8	

Our total net (loss) income attributable to common stock for 2010 decreased compared to 2009 by $5.4 billion, or $27.09 per share, mostly because of the following:

	Increase/(Decrease) 2010 vs. 2009
	(In millions, after-tax)
Generation gross margin, primarily due to the deconsolidation of CENG	$ (682)
Lower Generation operating expenses, primarily labor and benefit costs due to the deconsolidation of CENG	390
Lower Generation accretion expense of asset retirement obligations due to deconsolidation of CENG	37
Lower Generation taxes other than income taxes due to deconsolidation of CENG	27
Lower Generation depreciation and amortization due to deconsolidation of CENG	28
NewEnergy gross margin	78
NewEnergy hedge ineffectiveness	(55)
Loss on NewEnergy international coal contract assignments	(25)
Regulated businesses, excluding the effects of the 2009 residential customer credit	(21)
Other nonregulated businesses	5
Total change in *Other Items Included in Operations* per table below	(5,375)

All other changes		167
Total Change	$	(5,426)

Our total net income attributable to common stock for 2009 improved compared to 2008 by $5.8 billion, or $29.53 per share, mostly because of the following:

		Increase/(Decrease) 2009 vs. 2008
		(In millions, after-tax)
Generation gross margin	$	27
NewEnergy gross margin		(134)
Absence of sale of NewEnergy upstream gas assets		(16)
NewEnergy hedge ineffectiveness		84
Absence of NewEnergy credit loss coal supplier bankruptcy		33
Regulated businesses, excluding the effects of the 2008 Maryland settlement agreement and the 2009 residential customer credit		10
Other nonregulated businesses		(8)
Total change in *Other Items Included in Operations* per table below		5,763
All other changes		(1)
Total Change	$	5,758

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Other Items Included in Operations (after-tax):

	2010	2009	2008
		(In millions, after-tax)	
Impairment losses and other costs	**$ (1,487.1)**	$ (96.2)	$ (468.4)
Gain on Comprehensive Agreement with EDF	**121.3**		
Amortization of basis difference in CENG	**(117.5)**	(17.8)	
Impact of power purchase agreement with CENG (1)	**(113.3)**		
International coal contract dispute settlement	**35.4**		
Loss on early retirement of 2012 Notes	**(30.9)**		
Gain on sale of Mammoth Lakes geothermal generating facility	**24.7**		
Credit facility amendment/termination fees	**(13.6)**	(37.7)	
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**(8.8)**		
Gain on sale of 49.99% interest in CENG		4,456.1	
International commodities operation and gas trading operation (2)		(371.9)	
BGE residential customer rate credit		(67.1)	
Impairment of nuclear decommissioning trust assets		(46.8)	(82.0)
Merger termination and strategic alternatives costs		(13.8)	(1,204.4)
Loss on redemption of Zero Coupon Senior Notes		(10.0)	
Workforce reduction costs		(9.3)	(13.4)
Maryland settlement credit			(110.5)
Non-qualifying hedges			(70.1)
Emission allowance write down, net			(28.7)
Total Other Items	**$ (1,589.8)**	$ 3,785.5	$ (1,977.5)
Change from prior year	**$ (5,375.3)**	$ 5,763.0	

(1) *The net impact to the Company of the power purchase agreement with CENG was $185.6 million pre-tax for 2010. This amount represents the amortization of our $0.8 billion "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its $0.8 billion "Unamortized energy contract liability."*

(2) *These amounts include the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions were probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items for 2009 also include amounts related to the operations we divested.*

Generation Business

Background

Our Generation business is discussed in detail in *Item 1. Business Operating Segments* section.

We have presented the results of this business reflecting that we have hedged 100% of generation output and fuel for generation. This is based on executing hedges at prevailing market prices with the NewEnergy business. Taking into account previously executed hedges at the end of each fiscal year, we ensure that the Generation business is fully hedged by the NewEnergy business for the next year. Therefore, all commodity price risk is managed by and presented in the results of our NewEnergy business as discussed below. Generally, changes in the results of our Generation business during the period are due to changes in the availability of the generating assets.

During 2010, power prices continued to decline, reflecting economic conditions and projected increases in natural gas supplies. However, prices for coal have not declined to the same extent as power prices. The relationship between power and fuel prices directly affects the earnings of our Generation business. Although our NewEnergy business hedges portions of our future power sales and fuel purchases, the amounts we have hedged are higher for the near term and decline over time. We have already locked in prices for our expected generation output for 2011. However, consistent with our hedging approach, we have only hedged a portion of the expected output for 2012, and those hedges are at lower prices. If the current power and fuel price environment continues, we anticipate that our Generation business will have lower earnings in future years, especially in 2012.

Additionally, we evaluated our generating plants for impairment as a result of power price declines in 2010. Although none of our plants were impaired, further decreases in power prices could result in estimated future cash flows declining below the carrying value of our plants, which would require us to record an impairment charge.

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Results

	2010	2009	2008
		(In millions)	
Revenues	**$ 2,244.3**	$ 2,774.2	$ 2,958.5
Fuel and purchased energy expenses	**(1,444.8)**	(692.0)	(916.1)
Gross margin	**799.5**	2,082.2	2,042.4
Operating expenses	**(379.7)**	(1,008.4)	(969.1)
Impairment losses and other costs	**(2,476.7)**		(14.0)
Workforce reduction costs			(6.1)
Merger termination and strategic alternatives costs		(101.8)	(742.3)
Depreciation, depletion, and amortization	**(136.1)**	(176.8)	(174.3)
Accretion of asset retirement obligations	**(1.6)**	(62.1)	(67.9)
Taxes other than income taxes	**(23.6)**	(67.4)	(69.9)
Equity investment earnings (losses):			
CENG	**23.6**	4.3	
UNE	**(16.8)**	(24.7)	(5.9)
Other	**18.2**	20.6	32.7
Net gain on divestitures	**242.9**	7,445.6	
(Loss) Income from Operations	**$ (1,950.3)**	$ 8,111.5	$ 25.6
Net (Loss) Income	**$ (1,255.3)**	$ 4,766.7	$ (357.7)
Net (Loss) Income attributable to common stock	**$ (1,255.3)**	$ 4,766.7	$ (357.7)
Change from prior year	**$ (6,022.0)**	$ 5,124.4	
Other Items Included in Operations (after-tax):			
Impairment losses and other costs	**$ (1,487.1)**	$	$ (8.3)
Gain on Comprehensive Agreement with EDF	**121.3**		
Amortization of basis difference in CENG	**(117.5)**	(17.8)	
Impact of power purchase agreement with CENG (1)	**(113.3)**		
Loss on early retirement of 2012 Notes	**(30.9)**		
Gain on sale of Mammoth Lakes geothermal generating facility	**24.7**		
Credit facility amendment/termination fees	**(9.0)**	(13.7)	
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**(0.8)**		
Gain on sale of 49.99% interest in CENG		4,456.1	
Impairment of nuclear decommissioning trust assets		(46.8)	(82.0)
Loss on redemption of Zero Coupon Senior Notes		(10.0)	
Merger termination and strategic alternatives costs		(9.7)	(742.3)
Workforce reduction costs			(3.7)
Total Other Items	**$ (1,612.6)**	$ 4,358.1	$ (836.3)
Change from prior year	**$ (5,970.7)**	$ 5,194.4	

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.

(1) *The net impact to the Company of the power purchase agreement with CENG was $185.6 million pre-tax for2010. This amount represents the amortization of our $0.8 billion "Unamortized energy contract asset" less our 50.01% equity in CENG's amortization of its $0.8 billion "Unamortized energy contract liability."*

Effects of 2009 Transaction with EDF on Statement of Income (Loss)

Prior to November 6, 2009, CENG was a 100% owned subsidiary, and we consolidated its financial results within our Consolidated Statements of Income (Loss). On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF, and we deconsolidated CENG. Accordingly, beginning November 6, 2009, we ceased recording CENG's financial results and began to record equity investment earnings from CENG as well as the effect of our PPA and other transactions with CENG. We discuss our transaction with EDF in more detail in *Note 2 to Consolidated Financial Statements.*

For the period from January 1, 2009 through November 6, 2009, our Generation results included the following financial results of CENG:

For the period from January 1, 2009 through November 6, 2009

	(In billions)
Revenues	$ 1.2
Fuel and purchased energy expenses	0.1
Operating expenses	0.8
Depreciation and amortization	0.1
Income from operations	0.2

As a result of the deconsolidation, our Generation results after November 6, 2009 differ from historical results primarily due to the following factors:

Revenues We sell between 85-90% of the output of CENG's plants, excluding output sold by CENG directly to third parties, rather than 100% of the plants' total output including volumes contracted to third parties.

Fuel and purchased energy expenses We do not include nuclear fuel expense but instead reflect our purchase of between 85-90% of the output of CENG's plants, excluding output sold directly to third parties, as provided under the terms of the PPA with CENG.

Operating expenses We no longer include CENG's plant operating costs or general and administrative expenses.

Depreciation and amortization expense We no longer include deprecation of CENG's nuclear plants.

Additionally, we record our 50.01% share of CENG's financial results and amortization of the CENG basis difference in the "Equity Investment (Losses) Earnings" line in our Consolidated Statements of Income (Loss). We discuss the accounting for our retained investment in CENG in more detail in *Note 2 to Consolidated Financial Statements.*

Beginning in the fourth quarter of 2010, the amortization of the basis difference in CENG will be lower as the basis difference was reduced by the amount of the impairment charge recorded on our investment in CENG during the quarter ended September 30, 2010. We discuss the impairment charge in more detail in the *Note 2 to Consolidated Financial Statements.*

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Revenues

Our Generation revenues decreased $529.9 million in 2010 compared to 2009 and decreased $184.3 million in 2009 compared to 2008 primarily due to the following:

	2010 vs. 2009	2009 vs. 2008
	(In millions)	
Decrease in volume of output primarily due to the deconsolidation of CENG nuclear generating assets	**$ (690)**	$ (397)
Increase in volume of output due to the beginning of commercial dispatch of the Hillabee Energy Center and the acquisition of the Texas combined cycle generation facilities	**198**	
(Decrease) increase in volume of output due to (higher) lower planned and unplanned outages at our generating plants	**(127)**	150
Increase in higher contracted power prices for the output of our generating plants	**116**	65
All other	**(27)**	(2)
Total decrease in Generation revenues	**$ (530)**	$ (184)

Fuel and Purchased Energy Expenses

Our Generation fuel and purchased energy expenses increased $752.8 million in 2010 compared to 2009 and decreased $224.1 million in 2009 compared to 2008 primarily due to the following:

	2010 vs. 2009	2009 vs. 2008
	(In millions)	
Increase in purchased energy costs due to power purchase agreement with CENG compared with nuclear fuel costs	**$ 741**	$
(Decrease) increase in volume of output due to (higher) lower planned and unplanned outages at our generating plants	**(87)**	22
Increase (decrease) in fuel costs primarily related to higher (lower) contract prices to operate our generating assets	**59**	(273)
All other	**40**	27
Total increase (decrease) in Generation fuel and purchased energy expenses	**$ 753**	$ (224)

Operating Expenses

Our Generation business operating expenses decreased $628.7 million during 2010 as compared to 2009 due to lower labor and benefit costs of $499.9 million and lower non-labor operating expenses of $128.8 million, the majority of which results from the absence of costs in 2010 due to the deconsolidation of CENG.

Our Generation business operating expenses increased $39.3 million during 2009 as compared to 2008 due to higher performance-based labor and benefit costs of $74.5 million, partially offset by lower non-labor operating expenses of $35.2 million.

Impairment Losses and Other Costs

Our Generation business incurred impairment losses during 2010. These costs are discussed in more detail in *Note 2 to Consolidated Financial Statements*.

Depreciation, Depletion and Amortization Expense

Our Generation business incurred lower depreciation, depletion and amortization expenses of $40.7 million during 2010 compared to 2009 due to a decrease of $94.0 million in depreciation on the nuclear generating facilities resulting from the deconsolidation of CENG on November 6, 2009, partially offset by an increase of $53.4 million in depreciation on our other generating facilities primarily related to the installation of emission control equipment at our Brandon Shores coal-fired generating plant that went into service in the fourth quarter of 2009, the Texas combined cycle generation facilities we acquired in 2010, and the Hillabee Energy Center, which began commercial dispatch in 2010.

Our Generation business incurred higher depreciation, depletion and amortization expenses of $2.5 million during 2009 compared to 2008 due to an increase of $12.0 million in depreciation on our non-nuclear generating assets primarily related to environmental additions at our Brandon Shores coal-fired generating plant that went into service in the fourth quarter of 2009, partially offset by a $9.5 million decrease in depreciation on our nuclear generating assets resulting from the deconsolidation of CENG on November 6, 2009.

Accretion of Asset Retirement Obligations

Our Generation business incurred lower accretion of asset retirement obligations expense of $60.5 million in 2010 compared to 2009, which represents the absence of costs from deconsolidating CENG on November 6, 2009.

Our Generation business incurred lower accretion of asset retirement obligations expense of $5.8 million in 2009 compared to 2008, which represents the absence of costs from deconsolidating CENG on November 6, 2009.

Taxes Other Than Income Taxes

Our Generation business incurred lower taxes other than income taxes of $43.8 million in 2010 compared to 2009 and $2.5 million in 2009 compared with 2008, primarily due to lower property taxes as a result of the deconsolidation of CENG on November 6, 2009.

Equity Investment Earnings (Losses)

During 2010, our equity investment earnings increased $24.8 million as compared to 2009, primarily due to $19.3 million of higher earnings from our investment in CENG, $7.9 million of lower losses from our investment in UNE, which was sold in 2010, partially offset by $2.4 million of lower earnings on investments in power projects.

During 2009, our equity investment earnings decreased $26.6 million from 2008 primarily due to $18.8 million of higher losses from our investment in UNE and $12.1 million of lower earnings on investments in power projects, partially offset by $4.3 million in earnings related to our investment in CENG.

Additionally, CENG is involved in negotiations with certain tax jurisdictions in New York State with respect to agreements

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covering property tax payments on the Nine Mile Point nuclear generating facility. These negotiations may result in an increase in future property tax expenses for CENG, which in turn would reduce our equity investment earnings in CENG based on our 50.01% ownership interest. We are unable to determine the outcome of these negotiations at this time.

Net Gain on Divestitures

During 2010, we sold our Mammoth Lakes geothermal generating facility, recognizing a $38.0 million pre-tax gain, and our 50% interest in UNE in connection with our comprehensive agreement with EDF recognizing a $202.0 million pre-tax gain. We discuss our divestitures in more detail in *Note 2 to Consolidated Financial Statements.*

During 2009, we completed the sale of a 49.99% membership interest in CENG to EDF. As a result of this sale, we recognized a $7.4 billion pre-tax gain. We discuss this transaction in *Note 2 to Consolidated Financial Statements*.

NewEnergy Business

Background

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

Our NewEnergy business focuses on delivery of physical, customer-oriented energy products and services to energy producers and consumers, manages the risk and optimizes the value of our owned and contracted generation assets and NewEnergy activities, and uses our portfolio management and trading capabilities both to manage risk and to deploy limited risk capital. Our NewEnergy business actively transacts in energy and energy-related commodities in order to manage our portfolio of energy purchases and sales to customers through structured transactions.

We record NewEnergy revenues and expenses in our financial results in different periods depending upon the appropriate accounting treatment that represents the economics of the underlying transactions in our business. We discuss our revenue recognition policies in the *Critical Accounting Policies* section and *Note 1 to Consolidated Financial Statements*.

Results

	2010	2009	2008
		(In millions)	
Revenues	**$ 10,121.4**	$ 11,509.2	$ 15,851.7
Fuel and purchased energy expenses	**(8,877.6)**	(10,430.0)	(14,812.2)
Gross margin	**1,243.8**	1,079.2	1,039.5
Operating expenses	**(758.7)**	(763.6)	(932.7)
Impairment losses and other costs	**(0.1)**	(98.1)	(727.8)
Workforce reduction costs		(12.6)	(9.5)
Merger termination and strategic alternatives costs		(44.0)	(462.1)
Depreciation, depletion, and amortization	**(83.4)**	(82.5)	(118.7)
Accretion of asset retirement obligations	**(0.3)**	(0.2)	(0.5)
Taxes other than income taxes	**(52.8)**	(41.2)	(54.4)
Equity investment (losses) earnings		(6.3)	49.6
Net gain (loss) on divestitures	**2.5**	(468.8)	25.5
Income (Loss) from Operations	**$ 351.0**	$ (438.1)	$ (1,191.1)
Net Income (Loss)	**$ 176.2**	$ (348.2)	$ (1,011.4)
Net Income (Loss) attributable to common stock	**$ 138.6**	$ (402.3)	$ (994.2)
Change from prior year	**$ 540.9**	$ 591.9	

Other Items Included in Operations (after-tax):						
International coal contract dispute settlement	**$**	**35.4**	$		$	
Credit facility amendment/termination fees		**(4.6)**		(24.0)		
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits		**(0.1)**				
International commodities operation and gas trading operation (1)				(371.9)		
Impairment losses and other costs				(84.7)		(460.1)
Workforce reduction costs				(9.3)		(5.8)
Merger termination and strategic alternatives costs				(4.1)		(462.1)
Non-qualifying hedges						(70.1)
Emission allowance write-down, net						(28.7)
Total Other Items	**$**	**30.7**	$	(494.0)	$	(1,026.8)
Change from prior year	**$**	**524.7**	$	532.8		

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

(1) *Amount includes the net losses on the sales of the international commodities operation, gas trading operation, certain other trading operations, and a uranium market participant, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions were probable of not occurring, and earnings that are no longer part of our core business. The impairment losses and other costs and workforce reduction costs line items for 2009 also include amounts related to the operations we divested.*

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Revenues

Our NewEnergy revenues decreased $1,387.8 million in 2010 compared to 2009 and decreased $4,342.5 million in 2009 compared to 2008 primarily due to the following:

	2010 vs. 2009	2009 vs. 2008
	(In millions)	
Realization of lower wholesale load sales	**$ (917)**	$ (2,138)
(Decrease) increase in volume and contract prices related to our domestic coal operation	**(508)**	280
Realization of higher (lower) retail power load sales	**349**	(1,491)
Decrease due to the assignment of international coal and freight contracts, which we divested throughout 2009	**(321)**	(647)
Gain on sale of in-the-money wholesale load contract in the second quarter of 2009	**(106)**	106
Decrease in volumes at our retail gas and wholesale gas operation	**(77)**	(283)
Increase (decrease) in wholesale mark-to-market revenues due to changes in power and gas prices	**77**	(215)
Realization of higher revenues from our Maryland retail residential electric business	**49**	
Realization of construction and energy efficiency project revenues	**35**	
All other	**31**	45
Total decrease in NewEnergy revenues	**$ (1,388)**	$ (4,343)

Fuel and Purchased Energy Expenses

Our NewEnergy fuel and purchased energy expenses decreased $1,552.4 million in 2010 compared to 2009 and decreased $4,382.2 million in 2009 compared to 2008 primarily due to the following:

	2010 vs. 2009	2009 vs. 2008
	(In millions)	
Realization of fuel and purchased energy from wholesale power purchases	**$ (641)**	$ (2,541)
Decrease due to international coal and freight contracts, which we divested throughout 2009	**(540)**	(397)
(Decrease) increase in volume and contract prices related to our domestic coal operation	**(498)**	259
Increase (decrease) in volumes of retail power load purchases	**217**	(1,467)
Decrease in volumes at our retail gas and wholesale gas operation	**(83)**	(220)
All other	**(7)**	(16)
Total decrease in NewEnergy fuel and purchased energy expenses	**$ (1,552)**	$ (4,382)

Mark-to-Market

Mark-to-market results include net gains and losses from origination, risk management, certain physical energy delivery activities, and trading 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 to Consolidated Financial Statements*.

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

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

During 2009 and 2010, we focused our activities on reducing capital requirements, reducing long-term economic risk, and reducing short- and interim-term liquidity requirements. These actions may impact the future results of the NewEnergy business, particularly the size of and potential for changes in fair value of activities subject to mark-to-market accounting.

The primary components of mark-to-market results are origination gains and gains and losses from risk management and trading activities.

Origination gains arise primarily from contracts that our NewEnergy business structures to meet the risk management needs of our customers or relate to our trading activities. Transactions that result in origination gains may be unique and provide the potential for individually significant revenues and gains from a single transaction.

Risk management and trading mark-to-market represents both realized and unrealized gains and losses from changes in the value of our portfolio, including the effects of changes in valuation adjustments. In addition to our fundamental risk management and trading activities, we also use non-trading derivative contracts subject to mark-to-market accounting to manage our exposure to changes in market prices, while in general the underlying physical transactions related to these activities are accounted for on an accrual basis.

We discuss the changes in mark-to-market results below. We show the relationship between our mark-to-market results and the change in our net mark-to-market energy asset later in this section.

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Mark-to-market results were as follows:

	2010	2009	2008
		(In millions)	
Unrealized mark-to-market results			
Origination gains	**$**	$	$ 73.8
Risk management and trading mark-to-market			
Unrealized changes in fair value	**9.6**	(212.3)	159.8
Changes in valuation techniques			
Reclassification of settled contracts to realized	**(139.0)**	(265.4)	48.2
Total risk management and trading mark-to-market	**(129.4)**	(477.7)	208.0
Total unrealized mark-to-market (1)	**(129.4)**	(477.7)	281.8
Realized mark-to-market	**139.0**	265.4	(48.2)
Total mark-to-market results (2)	**$ 9.6**	$ (212.3)	$ 233.6

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

(2) *Includes gains (losses) on hedge ineffectiveness for fair value hedges recorded in gross margin.*

Total mark-to-market results increased $221.9 million during the year ended December 31, 2010 compared to the same period of 2009 due to unrealized changes in fair value primarily due to:

$197 million of higher results on open positions primarily due to the absence of losses in our power and transmission risk management activities in the PJM, Midwest, New York, and West regions as a result of a favorable price environment in 2010 and completion of our activities to reduce risk and improve liquidity,

$31 million of higher gains on open positions primarily due to the absence of losses in 2010 resulting from a more favorable price environment related to our retail power and gas businesses,

$18 million of higher results in our domestic coal portfolio primarily due to a more favorable price movement, and

$16 million of higher results on open positions due to a more favorable price environment related to economic hedges of our upstream gas operations and risk management activities.

These increases were partially offset by the absence of $40 million in results from our international coal and freight operations, which we divested in 2009.

Total mark-to-market results decreased $445.9 million during the year ended December 31, 2009 compared to the same period of 2008. The period-to-period variance in unrealized changes in fair value was due to decreased unrealized risk management and trading results of $372.1 million and the decrease in origination gains of $73.8 million. We discuss the decrease in origination gains below.

The decrease in risk management and trading results of $372.1 million was primarily due to:

$203 million of lower results in our domestic coal portfolio primarily as a result of less favorable price movements relating to economic hedges which substantially decreased in value as coal prices decreased in 2009,

$104 million due to the absence of gains in our international coal and freight operation as a result of its divestiture in March 2009,

- $123 million of lower gains in our wholesale natural gas risk management and trading operation primarily as a result of the divestiture of our natural gas trading operation in the beginning of April 2009, and
- $45 million of lower results related to our emissions trading activities primarily as a result of a less favorable price environment.

These decreases were partially offset by the following:

- $84 million of higher results on open positions primarily due to the absence of losses in our power and transmission risk management activities primarily in the PJM, Northeast, and New York regions as a result of a more favorable price environment in 2009 and our activities to reduce risk and improve liquidity, and
- $19 million of lower losses in our retail gas portfolio primarily due to a more favorable price environment in 2009.

We did not record any origination gains during 2010 and 2009. During 2008, our NewEnergy business amended certain nonderivative contracts to mitigate counterparty performance risk under the existing contracts. As a result of these amendments, the revised contracts became derivatives subject to mark-to-market accounting. The change in accounting for these contracts from nonderivative to derivative resulted in substantially all of the origination gains for 2008 presented in the unrealized mark-to-market results table above.

The recognition of origination gains is generally dependent on sufficient available market data that validates the initial fair value of the contract. Liquidity and market conditions impact our ability to identify sufficient, objective market price information to permit recognition of origination gains. As a result, 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.

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Derivative Assets and Liabilities

Derivative assets and liabilities consisted of the following:

At December 31,	**2010**	**2009**
	(In millions)	
Current assets	**$ 534.4**	$ 639.1
Noncurrent assets	**258.9**	633.9
Total assets	**793.3**	1,273.0
Current liabilities	**622.3**	632.6
Noncurrent liabilities	**353.0**	674.1
Total liabilities	**975.3**	1,306.7
Net derivative position	**$ (182.0)**	$ (33.7)
Composition of net derivative exposure:		
Hedges	**$ (504.5)**	$ (591.0)
Mark-to-market	**350.3**	524.3
Net cash collateral included in derivative balances	**(27.8)**	33.0
Net derivative position	**$ (182.0)**	$ (33.7)

Derivative balances above include noncurrent assets related to our Generation business of $35.7 million and $35.8 million at December 31, 2010 and December 31, 2009, respectively. Derivative balances related to our Generation business consist of interest rate contracts accounted for as fair value hedges.

As discussed in our *Critical Accounting Policies* section, our "Derivative assets and liabilities" include contracts accounted for as hedges and those accounted for on a mark-to-market basis. These amounts are presented in our Consolidated Balance Sheets after the impact of netting, which is discussed in more detail in *Note 1 to Consolidated Financial Statements*. Due to the impacts of commodity prices, the number of open positions, master netting arrangements, and offsetting risk positions on the presentation of our derivative assets and liabilities in our Consolidated Balance Sheets, we believe an evaluation of the net position is the most relevant measure, and is discussed in more detail below. However, we present our gross derivatives in *Note 13 to Consolidated Financial Statements.*

The decrease of $86.5 million in our net derivative liability subject to hedge accounting since December 31, 2009 was due to $700.0 million of realization of out-of-the-money cash-flow hedges at the time the forecasted transaction occurred, partially offset by $613.5 million of increases on our out-of-the-money cash-flow hedge positions primarily related to decreases in power, natural gas, and coal prices during 2010.

The following are the primary sources of the change in our net derivative asset subject to mark-to-market accounting during 2010 and 2009:

		2010		**2009**
		(In millions)		
Fair value beginning of year		**$ 524.3**		$ 1,485.9
Changes in fair value recorded in earnings				
Origination gains	**$**		$	
Unrealized changes in fair value	**9.6**		(212.3)	
Changes in valuation techniques				
Reclassification of settled contracts to realized	**(139.0)**		(265.4)	
Total changes in fair value		**(129.4)**		(477.7)

Changes in value of exchange-listed futures and options	**(197.1)**	97.8
Net change in premiums on options	**17.7**	84.9
Contracts acquired	**5.4**	(35.8)
Dedesignated contracts and other changes in fair value	**129.4**	(630.8)
Fair value at end of year	**$ 350.3**	$ 524.3

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

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

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

Changes in valuation techniques represent improvements in estimation techniques, including modeling and other statistical enhancements used to value our portfolio to more accurately reflect 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 derivative asset also changed due to the following items recorded in accounts other than in our Consolidated Statements of Income (Loss):

Changes in value of exchange-listed futures and options are recorded in "Accounts receivable" rather than "Derivative assets" in our Consolidated Balance Sheets because these

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amounts are settled through our margin account with a third party broker.

Net changes in premiums on options reflects the accounting for premiums on options purchased as an increase in the net derivative asset and premiums on options sold as a decrease in the net derivative asset.

Contracts acquired represents the initial fair value of acquired derivative contracts recorded in "Derivative assets and liabilities" in our Consolidated Balance Sheets. Substantially all of this activity for 2009 related to the divestiture of our international commodities operation, Houston-based gas trading operation, and certain other trading operations in order to transfer risk and reward to the buyers.

Dedesignated contracts and other changes in fair value include transfers of derivative contracts from cash-flow hedges to mark-to-market treatment, transfers of derivative contracts from mark-to-market treatment to cash-flow hedges, and those derivative contracts that did not meet the qualifications of cash flow hedge accounting. During 2009, substantially all of the activity related to dedesignations were in connection with the strategic objective of restructuring and reducing the risk of our portfolio.

The settlement terms of the portion of our net derivative asset subject to mark-to-market accounting and sources of fair value based on the fair value hierarchy are as follows as of December 31, 2010:

	Settlement Term							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Fair Value**
				(In millions)				
Level 1	$ 1.1	$	$	$	$	$	$	$ 1.1
Level 2	321.5	214.2	4.1	2.0	8.0	0.7	(0.1)	550.4
Level 3	43.2	(232.0)	(14.0)	6.0	5.0	4.2	(13.6)	(201.2)
Total net derivative asset (liability) subject to mark-to-market accounting	$ 365.8	$ (17.8)	$ (9.9)	$ 8.0	$ 13.0	$ 4.9	$ (13.7)	$ 350.3

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. Additionally, because the depth and liquidity of the power markets varies substantially between regions and time periods, the prices used to determine fair value could be affected significantly by the volume of transactions executed. 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 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 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).

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, many contracts are direct contracts between market participants and are not exchange-traded or financially settling contracts that can be readily offset 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.

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 preceding table. However, based upon the nature of our NewEnergy business, 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. Generally, we do not expect to realize the value of these contracts and related hedges by selling or assigning the contracts themselves in total.

Operating Expenses

Our NewEnergy business operating expenses decreased $169.1 million during 2009 as compared to 2008 due to lower labor and benefit costs of $126.0 million, primarily due to lower headcount resulting from the divestitures in 2009, and lower non-labor operating expenses of $43.1 million, part of which represents the absence of costs from the divestitures completed in 2009.

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Depreciation, Depletion and Amortization Expense

Our NewEnergy business incurred lower depreciation, depletion and amortization expenses of $36.2 million during 2009 compared to 2008 due to the absence of depletion expenses of $43.0 million as a result of divestitures made in 2008 in our upstream gas operations, partially offset by an increase of $6.8 million in other amortization primarily related to computer software placed in service in the fourth quarter of 2008.

Taxes Other Than Income Taxes

Our NewEnergy business incurred higher taxes other than income taxes of $11.6 million in 2010 compared to 2009, primarily due to higher gross receipts taxes related to an increase in retail revenues, primarily in Pennsylvania.

Our NewEnergy business incurred lower taxes other than income taxes of $13.2 million in 2009 compared to 2008, due to $8.1 million of lower gross receipts taxes resulting from a significant decrease in retail load revenues and $5.8 million of lower production taxes related to our upstream gas producing properties, partially offset by $0.7 million of higher property, franchise, and other taxes.

Equity Investment (Losses) Earnings

During 2009, our equity investment earnings decreased $55.9 million from 2008 primarily due to $39.1 million of lower earnings from our shipping joint venture as a result of the sale of our interests in July 2009, $12.3 million of lower earnings from our investment in CEP, and the absence of $4.5 million in earnings from investments in synfuel facilities.

Net Gain (Loss) on Divestitures

The table below summarizes the net gain (loss) on divestitures for our NewEnergy business:

	2010	2009	2008
Majority of our international commodities operation	$	$ (334.5)	$
Houston-based gas trading operation		(102.5)	
Uranium market participant		(27.2)	
Portfolio of contracts in our retail gas operations	**2.0**		
Various working interests in oil and natural gas producing properties and working interests in proved natural gas reserves and unproved properties			25.5
Other	**0.5**	(4.6)	
Total net gain (loss) on divestiture	**$ 2.5**	$ (468.8)	$ 25.5

We discuss these divestitures in more detail in *Note 2 to Consolidated Financial Statements.*

Regulated Electric Business

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

Results

	2010	2009	2008
		(In millions)	
Revenues	**$ 2,752.3**	$ 2,820.7	$ 2,679.7
Electricity purchased for resale expenses	**(1,680.9)**	(1,840.9)	(1,880.1)
Operations and maintenance expenses	**(449.3)**	(399.0)	(380.5)
Workforce reduction costs			(4.6)
Depreciation and amortization	**(205.2)**	(218.1)	(184.2)
Taxes other than income taxes	**(149.1)**	(142.9)	(139.1)
Income from Operations	**$ 267.8**	$ 219.8	$ 91.2

Net Income	**$ 110.0**	$ 79.1	$ 11.1
Net Income attributable to common stock	**$ 99.8**	$ 68.9	$ 1.1
Other Items Included in Operations (after-tax):			
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$ (3.1)**	$	$
Residential customer rate credit		(56.7)	
Maryland settlement credit			(110.5)
Workforce reduction costs			(2.8)
Total Other Items	**$ (3.1)**	$ (56.7)	$ (113.3)

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

Net income attributable to common stock from the regulated electric business increased $30.9 million in 2010 compared to 2009, mostly due to the absence in 2010 of $56.7 million after-tax in credits provided to customers in 2009 and a $7.7 million after-tax decrease in depreciation and amortization, partially offset by a $30.3 million after-tax increase in operations and maintenance expenses.

Net income attributable to common stock from the regulated electric business increased $67.8 million in 2009 compared to 2008, mostly due to a $53.8 million after-tax decrease in credits provided to customers.

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Electric Revenues

The changes in electric revenues in 2010 and 2009 compared to the respective prior year were caused by:

	2010 vs. 2009	2009 vs. 2008
	(In millions)	
Distribution volumes	**$ 32.7**	$ (6.3)
Base rates	**3.3**	
Residential customer rate credit	**95.0**	(95.0)
Nuclear decommissioning charges		18.7
Smart Energy Savers Program[SM] surcharges	**(22.0)**	29.3
Maryland settlement credit		189.1
Revenue decoupling	**(30.9)**	22.7
Standard offer service	**(154.2)**	(33.2)
Rate stabilization recovery	**2.5**	(2.7)
Financing credits	**0.4**	3.4
Senate Bill 1 credits	**(12.9)**	6.9
Total change in electric revenues from electric system sales	**(86.1)**	132.9
Other	**17.7**	8.1
Total change in electric revenues	**$ (68.4)**	$ 141.0

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 2010 and 2009 compared to the respective prior year were:

	2010	2009
Residential	**7.6%**	(1.3)%
Commercial	**3.5**	
Industrial	**(8.0)**	(6.7)

In 2010, we distributed more electricity to residential and commercial customers due to warmer summer and colder fourth quarter weather and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer.

In 2009, we distributed less electricity to residential customers due to decreased usage per customer, partially offset by colder winter weather and an increased number of customers. We distributed less electricity to industrial customers primarily due to decreased usage per customer.

Base Rates

On December 6, 2010, the Maryland PSC issued an abbreviated order authorizing BGE to increase electric distribution rates by $31.0 million for service rendered on or after December 4, 2010. This increase was based upon an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio. We discuss BGE's electric base rates in the *Regulation Maryland Base Rates* section.

Residential Customer Rate Credit

On October 30, 2009, the Maryland PSC issued an order approving Constellation Energy's transaction with EDF. Among other things, the order required Constellation Energy to fund a one-time distribution rate credit for BGE residential customers before the end of March 2010 totaling $110.5 million, or approximately $100 per customer, for which BGE recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating BGE would give residential customers a rate credit of exactly $100 per customer. As a result, BGE accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. The portion of this total credit allocated to residential electric customers was $95.0 million pre-tax. This credit was accrued in the fourth quarter of 2009 and applied to BGE residential electric customer bills in the first quarter of 2010.

Nuclear Decommissioning Charges

Effective January 1, 2009, BGE and Calvert Cliffs Nuclear Power Plant Inc. (Calvert Cliffs) mutually agreed to terminate the decommissioning funds collection agent agreement, which was effective from July 1, 2000 to December 31, 2008. As a result, BGE ceased transferring funds to provide for the decommissioning of Calvert Cliffs Unit 1 and Unit 2. Calvert Cliffs retains the obligation to provide adequate assurances of funding pursuant to Nuclear Regulatory Commission requirements. Under the 2008 Maryland settlement agreement, BGE will continue to provide certain credits to residential customers and assess certain charges to all customers relating to decommissioning.

Smart Energy Savers Program℠ Surcharge

Beginning in 2009, the Maryland PSC approved customer surcharges through which BGE recovers costs associated with certain programs designed to help BGE manage peak demand and encourage customer energy conservation through the use of customer bill credits.

Revenues declined in 2010 compared to 2009, primarily due to an increase in customer involvement in our programs. This increased participation increased customer credits and, therefore, decreased revenues.

Revenues increased in 2009 compared to 2008, primarily due to $29.3 million of customer surcharge revenues from the new programs implemented in 2009 that were not in place in 2008.

Maryland Settlement Credit

As discussed in more detail in *Note 2 to Consolidated Financial Statements*, BGE entered into a settlement agreement with the State of Maryland and other parties, which provided residential electric customers a credit totaling $170 per customer. The estimated settlement of $188.2 million was accrued in the second quarter of 2008 and a total of $189.1 million was credited to customers in the third and fourth quarters of 2008.

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Revenue Decoupling

The Maryland PSC has allowed us to record a monthly adjustment to our electric distribution revenues from residential and small commercial customers since 2008 and for the majority of our large commercial and industrial customers since February 2009 to eliminate the effect of abnormal weather and usage patterns per customer on our electric distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Standard Offer Service

BGE provides standard offer service for customers that do not select an alternative supplier.

Standard offer service revenues decreased in 2010 compared to 2009 mostly due to lower standard offer service rates and volumes.

Standard offer service revenues decreased in 2009 compared to 2008 mostly due to lower standard offer service volumes, partially offset by higher standard offer service rates.

Rate Stabilization Recovery

In late June 2007, BGE began recovering amounts deferred during the first rate deferral period that began in July 2006 and ended on May 31, 2007. The recovery of the first rate stabilization plan is occurring over a ten year period. In April 2008, BGE began recovering amounts deferred during the second rate deferral period that began in June 2007 and ended on December 31, 2007. The recovery of the second rate deferral occurred over a 21-month period that began April 1, 2008 and ended on December 31, 2009.

Financing Credits

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

Senate Bill 1 Credits

As a result of Senate Bill 1, beginning January 1, 2007, we were required to provide to residential electric customers a credit equal to the amount collected from all BGE electric customers for the decommissioning of our Calvert Cliffs Nuclear Power Plant and to suspend collection of the residential return component of the administrative charge collected through residential SOS rates through May 31, 2007. Under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, we were required to reinstate collection of the residential return component of the administration charge in rates and to provide all residential electric customers a credit for the residential return component of the administrative charge. Under the 2008 Maryland settlement agreement, which is discussed in more detail in *Note 2 to Consolidated Financial Statements*, BGE was allowed to resume collection of the residential return portion of the administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to residential customers.

The decrease in revenues during 2010 compared to 2009 is primarily due to the reinstatement of the credit for the residential return component of the administrative charge on June 1, 2010 and higher distribution volumes.

The increase in revenues during 2009 compared to 2008 is primarily due to the absence of the credit for the residential return component of the administrative charge which was suspended under the Maryland settlement agreement, partially offset by lower distribution volumes.

Electricity Purchased for Resale Expenses

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

	2010	2009	2008

		(In millions)	
Actual costs	**$ 1,618.3**	$ 1,781.9	$ 1,821.1
Recovery under rate stabilization plans	**62.6**	59.0	59.0
Electricity purchased for resale expenses	**$ 1,680.9**	$ 1,840.9	$ 1,880.1

Actual Costs

BGE's actual costs for electricity purchased for resale decreased $163.6 million for 2010 compared to 2009, mostly due to lower standard offer service rates and volumes.

BGE's actual costs for electricity purchased for resale decreased $39.2 million for 2009 compared to 2008, primarily due to lower standard offer service volumes, partially offset by higher standard offer service rates.

Recovery under Rate Stabilization Plans

Between July 2006 and May 31, 2007, we deferred $287.3 million in electricity purchased for resale expenses representing the difference between our actual costs of electricity purchased for resale and what we are allowed to bill customers under Senate Bill 1. These deferred expenses, plus carrying charges, are included in "Regulatory Assets (net)" in our, and BGE's, Consolidated Balance Sheets.

In late June 2007, we began recovering previously deferred amounts from customers. We recovered $62.6 million, $59.0 million, and $59.0 million in 2010, 2009, and 2008, respectively, in deferred electricity purchased for resale expenses. These collections secure the payment of principal and interest

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and other ongoing costs associated with rate stabilization bonds issued by a subsidiary of BGE in June 2007.

Electric Operations and Maintenance Expenses

Regulated electric operations and maintenance expenses increased $50.3 million in 2010 compared to 2009, primarily due to increased distribution service restoration expenses of $24.2 million, $13.4 million of higher labor and benefits costs, and the impact of inflation on other costs of $12.7 million.

Regulated electric operations and maintenance expenses increased $18.5 million in 2009 compared to 2008, primarily due to increased uncollectible accounts receivable expense of $5.1 million and the impact of inflation on other costs of $8.0 million.

Electric Depreciation and Amortization Expense

Regulated electric depreciation and amortization expense decreased $12.9 million during 2010, compared to 2009, primarily due to decreased amortization of $22.9 million of deferred Smart Energy Savers Program^{SM} costs due to a regulatory change in the deferral period associated with these costs, partially offset by a $7.0 million increase in property, plant and equipment depreciation.

Regulated electric depreciation and amortization expense increased $33.9 million during 2009, compared to 2008, primarily due to $43.3 million in increased amortization expense associated with the Smart Energy Savers Program^{SM} and additional property placed in service in 2009, partially offset by $18.7 million in lower depreciation expense as a result of revised depreciation rates which were implemented on June 1, 2008 for regulatory and financial reporting purposes as part of the Maryland settlement agreement.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $6.2 million during 2010 compared to 2009, primarily due to the absence in 2010 of the impact of lower customer credits on franchise taxes of $95.0 million pre-tax.

Taxes other than income taxes increased $3.8 million during 2009 compared to 2008, primarily due to the impact of $94.1 million pre-tax in lower customer credits on franchise taxes.

Regulated Gas Business

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

Results

	2010	**2009**	**2008**
		(In millions)	
Revenues	**$ 709.4**	$ 758.3	$ 1,024.0
Gas purchased for resale expenses	**(387.5)**	(449.9)	(694.5)
Operations and maintenance expenses	**(156.8)**	(160.9)	(157.3)
Workforce reduction costs			(1.8)
Depreciation and amortization	**(44.0)**	(44.0)	(43.7)
Taxes other than income taxes	**(34.7)**	(34.9)	(35.4)
Income from Operations	**$ 86.4**	$ 68.6	$ 91.3
Net Income	**$ 37.6**	$ 25.5	$ 40.4
Net Income attributable to common stock	**$ 34.6**	$ 22.5	$ 37.2
Other Items Included in Operations (after-tax):			
Residential customer rate credit	**$**	$ (10.4)	$

Workforce reduction costs			(1.0)
Total Other Items	$	$ (10.4)	$ (1.0)

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 attributable to common stock from the regulated gas business increased $12.1 million in 2010 compared to 2009, primarily due to the absence in 2010 of the accrual of a customer rate credit of $10.4 million after-tax recorded in 2009.

Net income attributable to common stock from the regulated gas business decreased $14.7 million in 2009 compared to 2008, primarily due to the accrual of a customer rate credit of $10.4 million after-tax and increased operations and maintenance expenses of $2.2 million after-tax.

Gas Revenues

The changes in gas revenues in 2010 and 2009 compared to the respective prior year were caused by:

	2010 vs. 2009	**2009 vs. 2008**
	(In millions)	
Distribution volumes	**$ 3.1**	$ 1.5
Base rates	**1.6**	
Residential customer rate credit	**17.4**	(17.4)
Conservation surcharge	**(1.0)**	1.0
Revenue decoupling	**(3.1)**	(1.8)
Gas cost adjustments	**(69.1)**	(130.0)
Total change in gas revenues from gas system sales	**(51.1)**	(146.7)
Off-system sales	**(1.2)**	(116.6)
Other	**3.4**	(2.4)
Total change in gas revenues	**$ (48.9)**	$ (265.7)

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Distribution Volumes

The percentage changes in our distribution volumes, by type of customer, in 2010 and 2009 compared to the respective prior year were:

	2010	2009
Residential	1.1%	0.9%
Commercial	(3.2)	(10.6)
Industrial	(5.2)	12.5

In 2010, we distributed more gas to residential customers, mostly due to increased usage per customer and an increased number of customers. We distributed less gas to commercial customers, mostly due to decreased usage per customer. We distributed less gas to industrial customers, mostly due to decreased usage per customer.

In 2009, we distributed more gas to residential customers due to colder winter weather. We distributed less gas to commercial customers due to decreased usage per customer, partially offset by an increased number of customers and colder weather. We distributed more gas to industrial customers mostly due to increased usage per customer, partially offset by a decreased number of customers.

Base Rates

On December 6, 2010, the Maryland PSC issued an abbreviated order authorizing BGE to increase gas distribution rates by $9.8 million for service rendered on or after December 4, 2010. This increase was based upon a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio. We discuss BGE's gas base rates in the *Regulation Maryland Base Rates* section.

Residential Customer Rate Credit

On October 30, 2009, the Maryland PSC issued an order approving Constellation Energy's transaction with EDF. Among other things, the order required Constellation Energy to fund a one-time distribution rate credit for BGE residential customers totaling $110.5 million, or approximately $100 per customer, for which BGE recorded a liability in November 2009. In December 2009, BGE filed a tariff with the Maryland PSC stating BGE would give residential customers a rate credit of exactly $100 per customer. As a result, BGE accrued an additional $1.9 million for a total fourth quarter 2009 accrual of $112.4 million. The portion of this total credit allocated to residential gas customers was $17.4 million pre-tax. This credit was accrued in the fourth quarter of 2009 and applied to BGE residential gas customer bills in the first quarter of 2010.

Conservation Surcharge

Beginning February 2009, the Maryland PSC approved a customer surcharge through which BGE recovers costs associated with certain programs designed to help BGE encourage customer conservation.

Gas Revenue Decoupling

The Maryland PSC allows us to record a monthly adjustment to our gas distribution revenues to eliminate the effect of abnormal weather and usage patterns per customer on our gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at Maryland PSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. We then bill or credit impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Gas Cost Adjustments

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

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

Gas cost adjustment revenues decreased in both 2010 compared to 2009 and in 2009 compared to 2008 because we sold less gas at lower prices.

Off-System Gas Sales

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

Revenues from off-system gas sales decreased in 2010 compared to 2009 because we sold less gas, partially offset by higher prices.

Revenues from off-system gas sales decreased in 2009 compared to 2008 because we sold less gas at lower prices.

Gas Purchased For Resale Expenses

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

Gas costs decreased $62.4 million in 2010 compared to 2009 and decreased $244.6 million in 2009 compared to 2008 because we purchased less gas at lower prices.

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Gas Operations and Maintenance Expenses

Regulated gas operation and maintenance expenses decreased $4.1 million during 2010 compared to 2009, primarily due to decreased uncollectible accounts receivable expense of $4.7 million.

Regulated gas operation and maintenance expenses increased $3.6 million during 2009 compared to 2008, primarily due to increased uncollectible accounts receivable expense of $2.0 million.

Holding Company and Other Nonregulated Businesses

Results

	2010	2009	2008
		(In millions)	
Revenues	**$ 1.2**	$ 14.4	$ 16.1
Operating expenses	**53.1**	56.5	54.3
Impairment losses and other costs		(26.6)	
Workforce reduction costs			(0.2)
Depreciation and amortization	**(48.9)**	(67.7)	(62.3)
Taxes other than income taxes	**(3.7)**	(4.0)	(3.0)
Gain on divestitures	**0.4**		
Income (Loss) from Operations	**$ 2.1**	$ (27.4)	$ 4.9
Net Loss	**$ (0.3)**	$ (19.7)	$ (0.8)
Net Loss attributable to common stock	**$ (0.3)**	$ (12.4)	$ (0.8)
Other Items Included In Operations (after-tax):			
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits	**$ (4.8)**	$	$
Impairment losses and other costs		(11.5)	
Workforce reduction costs			(0.1)
Total Other Items	**$ (4.8)**	$ (11.5)	$ (0.1)

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

Net loss attributable to common stock for 2010 decreased $12.1 million compared to 2009 primarily due to the absence in 2010 of an impairment of a district chilled water energy plant of $7.1 million after-tax and reduction for noncontrolling interest, and a write-off of an uncollectible advance to an affiliate of $4.3 million after-tax.

Net loss attributable to common stock for 2009 increased $11.6 million compared to 2008 primarily due to increased impairment losses and other costs due to an impairment of a district chilled water energy plant of $7.1 million after-tax and reduction for noncontrolling interest, a write-off of an uncollectible advance to an affiliate of $4.3 million after-tax, and higher depreciation and amortization expense of $3.2 million after-tax as a result of increased property additions during 2008.

Consolidated Nonoperating Income and Expenses

Other (Expenses) Income

In 2010, we had other expenses of $76.7 million and, in 2009, we had other expenses of $140.7 million. The $64.0 million decrease in 2010 compared to 2009 is mostly due to the absence in 2010 of $62.6 million of other-than-temporary impairment charges related to nuclear decommissioning trust fund assets recorded in 2009.

In 2009, we had other expenses of $140.7 million and, in 2008, we had other expenses of $69.5 million. The $71.2 million increase in 2009 compared to 2008 is mostly due to higher credit facility costs, including amortization of amendment fees.

Other income at BGE decreased $4.6 million in 2010 compared to 2009 primarily due to decreases in interest and investment income of $3.3 million.

Other income at BGE decreased $4.2 million in 2009 compared to 2008 primarily due to decreases in interest and investment income of $4.2 million.

Fixed Charges

Fixed charges decreased $72.3 million in 2010 compared to 2009 mostly due to a lower level of interest expense due to repayments of debt made in 2009, partially offset by a $51.6 million loss recognized in February 2010 on the retirement of $486.5 million of our 7.00% Notes due April 1, 2012. We discuss this transaction in more detail in *Note 9 to Consolidated Financial Statements*.

Fixed charges at BGE decreased $9.0 million in 2010 compared to 2009 mostly due to a lower level of interest expense due to repayments of debt in 2009.

Income Taxes

Income tax expense decreased $3,652.5 million during 2010 compared to 2009 mostly due to a decrease in income before income taxes as a result of the absence in 2010 of the approximately $7.4 billion gain on sale of our 49.99% membership interest in CENG recorded in 2009 and the recognition of approximately $2.5 billion of impairment charges in 2010.

Income tax expense increased $3,065.1 million during 2009 compared to 2008 mostly due to higher income before income taxes due to the recognition of the $7.4 billion pre-tax gain on closing the transaction to sell a 49.99% membership interest in CENG. Additionally, there was lower income before income taxes for 2008, primarily due to approximately $1.2 billion of non-tax deductible merger termination and strategic alternative costs. However, in 2009, certain of these costs became tax deductible as a result of closing the EDF transaction and we recorded a tax benefit for these items in 2009.

BGE's income tax expense increased $33.3 million during 2010, mostly due to an increase in income before income taxes.

BGE's income tax expense increased $43.1 million during 2009, mostly due to higher pre-tax income. For 2008, BGE had a lower effective tax rate as a result of a reduction in its 2008 taxable income due to the impact of certain provisions of the 2008 Maryland settlement agreement, which increased the relative impact of the favorable permanent tax adjustments on its effective tax rate.

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Defined Benefit Plans Funded Status

At December 31, 2010, the total projected benefit obligations of our qualified and nonqualified pension plans exceeded the fair value of our qualified pension plan assets by $218.0 million. At December 31, 2009, the total projected benefit obligations of our qualified and nonqualified pension plans exceeded the fair value of our qualified pension plan assets by $411.7 million. The $193.7 million improvement in the funded status of our pension plans in 2010 primarily reflects the following:

- the contribution of $279.7 million into our qualified pension plan trusts during 2010, and
- $148.8 million in actual returns on qualified pension plan assets during 2010.

These increases were partially offset by normal growth in the projected benefit obligations of our qualified and nonqualified pension plans, including a 50 basis point decrease in the discount rate at December 31, 2010 compared to December 31, 2009.

At December 31, 2010, our accumulated post retirement benefit obligations totaled $334.9 million compared to $322.3 million at December 31, 2009. The $12.6 million increase in obligations for these unfunded plans primarily reflects the 50 basis point decrease in the discount rate at December 31, 2010 compared to December 31, 2009.

Our other postemployment benefit obligation increased $4.4 million from $50.6 million at December 31, 2009 to $55.0 million as of December 31, 2010, primarily due to a 75 basis point decrease in the discount rate.

We discuss our defined benefit plans in further detail in *Note 7 to Consolidated Financial Statements*.

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Financial Condition

Cash Flows

The following table summarizes our 2010 cash flows by business segment, as well as our consolidated cash flows for 2010, 2009, and 2008.

	2010 Segment Cash Flows				Consolidated Cash Flows		
	Generation	NewEnergy	Regulated	Eliminations, Holding Company and Other	2010	2009	2008
	(In millions)						
Operating Activities							
Net (loss) income	$ (1,255.3)	$ 176.2	$ 147.6	$ (0.3)	$ (931.8)	$ 4,503.4	$ (1,318.4)
Non-cash merger termination and strategic alternatives costs						128.2	541.8
Derivative contracts classified as financing activities (1)		186.0			186.0	1,138.3	(107.2)
Gain on sale of 49.99% membership interest in CENG						(7,445.6)	
(Gain) loss on divestitures	(242.9)	(2.5)		(0.4)	(245.8)	468.8	(38.1)
Accrual of BGE residential customer credit						112.4	
Impairment losses and other costs	2,476.7	0.1			2,476.8	124.7	741.8
Other non-cash adjustments to net (loss) income	(506.9)	(11.4)	620.9	53.6	156.2	2,761.0	602.9
Changes in working capital							
Derivative assets and liabilities, excluding collateral	(1.9)	452.1	(0.3)		449.9	425.3	(757.9)
Net collateral and margin		41.3	2.9		44.2	1,522.8	(960.3)
Accrued taxes	(1,123.2)	(58.6)	(60.8)	432.7	(809.9)	102.1	79.7
Other changes	(241.8)	281.1	(199.0)	(431.8)	(591.5)	664.9	13.9
Defined benefit obligations (2)					(224.5)	(287.2)	(20.8)
Other	71.9	(81.6)	(31.9)	43.3	1.7	171.7	(38.5)
Net cash (used in) provided by operating activities	(823.4)	982.7	479.4	97.1	511.3	4,390.8	(1,261.1)
Investing Activities							
Investments in property, plant and equipment	(331.9)	(141.6)	(496.8)	(25.3)	(995.6)	(1,529.7)	(1,934.1)
Asset acquisitions and business combinations, net of cash acquired	(372.9)	(72.9)			(445.8)	(41.1)	(315.3)
Change in cash pool (3)	(2,321.1)	136.7	314.7	1,869.7			
Contributions to nuclear decommissioning trust funds						(18.7)	(18.7)
Investments in joint ventures						(201.6)	
Proceeds from sale of 49.99% membership interest in CENG						3,528.7	
Proceeds from sale of investments and other assets	212.5	9.6		21.9	244.0	88.3	446.3
Proceeds from investment tax credits and grants related to renewable energy investments	39.0	17.5			56.5		
Contract and portfolio acquisitions	(1.0)	(207.3)			(208.3)	(2,153.7)	
(Increase) decrease in restricted funds	(50.0)	(5.8)	(5.1)	0.6	(60.3)	1,003.3	(942.8)
Other investments	(39.6)	4.1		(0.2)	(35.7)	0.1	21.7

Net cash (used in) provided by investing activities	(2,865.0)	(259.7)	(187.2)	1,866.7	(1,445.2)	675.6	(2,742.9)
Cash flows from operating activities plus cash flows from investing activities	$ (3,688.4)	$ 723.0	$ 292.2	$ 1,963.8	(933.9)	5,066.4	(4,004.0)
Financing Activities (2)							
Net (repayment) issuance of debt					(128.1)	(2,660.4)	3,447.7
Debt and credit facility costs					(32.8)	(98.4)	(104.8)
Proceeds from issuance of common stock					14.0	33.9	17.6
Common stock dividends paid					(183.3)	(228.0)	(336.3)
BGE preference stock dividends paid					(13.2)	(13.2)	(13.2)
Reacquisition of common stock							(16.2)
Proceeds from contract and portfolio acquisitions					52.2	2,263.1	
Derivative contracts classified as financing activities (1)					(186.0)	(1,138.3)	107.2
Other					(0.4)	12.7	8.3
Net cash (used in) provided by financing activities					(477.6)	(1,828.6)	3,110.3
Net (decrease) increase in cash and cash equivalents					$ (1,411.5)	$ 3,237.8	$ (893.7)

(1) *All ongoing cash flows from derivative contracts deemed to contain a financing element at inception must be reclassified from operating activities to financing activities.*

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

(3) *As part of the ring-fencing measures required by the Maryland PSC in its 2009 order approving the transaction with EDF, BGE ceased participation in the cash pool on January 7, 2010. We discuss this ring-fencing measure in Notes to Consolidated Financial Statements.*

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Cash Flows from Operating Activities

In 2010, cash provided by operating activities of $0.5 billion reflected $0.5 billion from our regulated business, $0.2 billion from our competitive businesses, and $0.1 billion from holding company and other businesses. These were partially offset by $0.3 billion of contributions to our qualified pension plan. The $0.2 billion of operating cash flows from our competitive businesses included $0.8 billion of federal income tax payments on the 2009 EDF transaction.

The $3.9 billion decrease in operating cash flows for 2010 compared to 2009 is primarily due to:

$1.0 billion higher income taxes paid,

$0.3 billion of lower operating cash flows from our regulated businesses, primarily due to the residential customer rate credit in the first quarter of 2010 and higher distribution service restoration expenses associated with 2010 storms,

$1.0 billion lower derivative contract settlements reclassified as financing activities in 2010, and

$1.5 billion lower net collateral and margin returned in 2010 as compared to 2009 as follows:

	December 31, 2010	December 31, 2009
	(In millions)	
Net collateral and margin held (posted), beginning of year	$ 77.2	$ (1,445.6)
Return of collateral held associated with nonderivative contracts	(16.1)	(17.0)
Net (additional) return of collateral posted associated with nonderivative contracts	(7.4)	336.3
Return of initial and variation margin posted on exchange-traded transactions recorded in accounts receivable	6.9	924.8
Return of fair value net cash collateral posted (netted against derivative assets/liabilities)*	60.8	278.7
Change in net collateral and margin posted	44.2	1,522.8
Net collateral and margin held, end of year	$ 121.4	$ 77.2

* *We discuss our netting of fair value collateral with our derivative assets/liabilities in more detail in Note 13 to Consolidated Financial Statements.*

Cash provided by operating activities was $4.4 billion in 2009 compared to cash used in operating activities of $1.3 billion in 2008. This $5.7 billion increase in cash flows was primarily due to:

$1.2 billion as a result of ongoing cash outflows from derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities. We discuss the impact on cash flows from financing activities below.

$1.2 billion related to changes in net derivative assets and liabilities. Changes in derivative assets and liabilities are driven by fluctuations in commodity prices and the realization of contracts at settlement within our NewEnergy business.

$0.5 billion of improved operating cash flows from our regulated businesses.

$2.5 billion more in net collateral and margin returned in 2009 as compared to 2008.

Cash Flows from Investing Activities

Cash used in investing activities was $1.4 billion in 2010 compared to cash provided by investing activities of $0.7 billion in 2009. The $2.1 billion increase in cash used in 2010 compared to 2009 was primarily due to:

- the absence of $3.5 billion of net proceeds received at the closing the sale of a 49.99% membership interest in CENG to EDF in 2009. We discuss this transaction in more detail in *Note 2 to Consolidated Financial Statements*.
- $1.1 billion of lower restricted funds activity in 2010. In January 2009, our restricted funds decreased by $1.0 billion, primarily due to the release of restricted funds for the repayment of $1 billion of 14% Senior Notes to MidAmerican.
- $0.4 billion increase in cash used for asset and business acquisitions. We discuss our acquisitions in the *Note 15 to Consolidated Financial Statements*.

These increases were offset by:

- $1.9 billion lower outflows associated with contract and portfolio acquisitions resulting from the structure of the divestiture of a majority of our international commodities operation in March 2009,
- $0.7 billion of lower investments in property, plant, and equipment and in the CENG and UNE joint ventures, primarily related to environmental additions at our Brandon Shores coal-fired generating plant that went into service in the fourth quarter of 2009 and the absence of nuclear capital spending in 2010 due to the deconsolidation of CENG in 2009, and
- $0.2 billion of higher proceeds from investment tax credits and grants related to renewable energy investments and proceeds on the sale of investments (primarily the sale of our 50% interest in UNE).

Cash provided by investing activities was $0.7 billion in 2009 compared to cash used of $2.7 billion in 2008. The $3.4 billion increase in cash provided in 2009 compared to 2008 was primarily due to:

- $3.5 billion of net proceeds at the closing of the sale of a 49.99% membership interest in CENG to EDF. We discuss this transaction in more detail in *Note 2 to Consolidated Financial Statements*. There was no such activity in 2008,
- $1.9 billion decrease in restricted funds, primarily due to the receipt of funds in 2008 and the release of funds

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in 2009 for the repayment of the $1 billion of 14% Senior Notes to MidAmerican in January 2009, and

$0.3 billion decrease in cash used for acquisitions. In 2009, $20.8 million was used for the acquisition of CLT Energy Services Group, doing business as CLT Efficient Technologies Group, an energy services company that provides energy performance contracting and energy efficiency engineering services, and $20.3 million was used as a down payment for the pending acquisition of the Criterion wind project in Garrett County, Maryland. In 2008, $0.3 billion was used for the acquisition of the Hillabee Energy Center, a partially completed 740 MW gas-fired combined cycle power generation facility in Alabama; the West Valley Power Plant, a 200 MW gas-fired peaking plant; and a uranium market participant.

This increase was partially offset by:

$2.2 billion of cash used for contract and portfolio acquisitions as a component of our strategic divestitures. As a result of the structure of the divestitures of a majority of our international commodities, Houston-based gas trading and other trading operations, we are required to present investing cash flows for in-the-money contracts on a gross basis separate from financing cash inflows for out-of-the-money contracts executed simultaneously. We discuss our divestitures in more detail in *Note 2 to Consolidated Financial Statements*. There was no such activity in 2008.

$0.2 billion of cash used for a working capital investment in CENG of $0.1 billion and a contribution to UNE of $0.1 billion.

Cash Flows from Financing Activities

Cash used in financing activities was $0.5 billion in 2010 compared to cash used in financing activity of $1.8 billion in 2009. The decrease in cash used for financing activities of $1.3 billion was primarily due to:

$2.5 billion lower net debt repayments in 2010 compared to 2009. In 2009, we repaid $1.0 billion of 14% Senior Notes, $0.8 billion in short-term borrowings on our credit facilities, $0.5 billion of 6.125% Fixed Rate Notes, and $0.3 billion of Zero Coupon Senior Notes. In 2010, we retired $0.5 billion 7.00% Notes due April 1, 2012 pursuant to a cash tender offer and repurchased outstanding Tax Exempt Variable Rate Notes totaling $0.1 billion. These debt retirements were substantially offset by the issuance of $0.6 billion of 5.15% Fixed Rate Notes in December 2010.

$1.0 billion lower cash outflows related to derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities in 2010 compared to 2009. These contracts primarily related to transactions associated with the divestiture of our Houston-based gas trading operation in March 2009, when we executed transactions at prices that differed from market prices. As a result, for cash flows associated with the out-of-the money derivative transactions executed, we recorded the ongoing cash flows related to these contracts as financing cash flows in March 2009.

This decrease was partially offset by $2.2 billion of lower proceeds from contract and portfolio acquisitions related to the structure of the divestiture of the majority of our international commodities operation in March 2009.

Cash used in financing activities was $1.8 billion in 2009 compared to cash provided of $3.1 billion in 2008. The increase in cash used for financing activities of $4.9 billion was primarily due to:

$3.0 billion net increase in cash used to repay short-term borrowings and long-term debt primarily due to the repayment of the $1 billion 14% Senior Notes to MidAmerican in January 2009, $1.6 billion in net repayments of short-term credit facilities, $0.5 billion repayment of a 6.125% fixed rate note, and a $0.3 billion repayment of Zero Coupon Senior Notes,

$3.1 billion net decrease in cash received from the issuance of long-term debt, and

$1.2 billion in cash outflows related to derivative contracts deemed to contain a financing element at inception that must be classified as financing activities rather than operating activities. These contracts primarily relate to transactions associated with the divestiture of our international commodities operation, Houston-based gas trading operation and certain other trading operations. During 2009, we executed derivatives as part of these divestiture transactions at prices that differed from then-current market prices. As a result, cash flows associated with the out-of-the money derivative transactions are deemed to contain a financing element, and we must record the ongoing cash flows related to these contracts as financing cash flows. We discuss our divestitures in more detail in *Note 2 to Consolidated Financial Statements.*

This increase in cash used for financing activities was partially offset by $2.3 billion of cash provided from contract and portfolio acquisitions as a component of our strategic divestitures. As a result of the structure of the divestitures of a majority of our international commodities, Houston-based gas trading and other trading operations, we are required to present financing cash inflows for out-of-the-money contracts on a gross basis separate from investing cash outflows for in-the-money contracts executed simultaneously. We discuss our divestitures in more detail in *Note 2 to Consolidated Financial Statements.* There was no such activity in 2008.

Contract and Portfolio Acquisitions

During 2010 and 2009, our NewEnergy business acquired several pre-existing energy purchase and sale agreements, which generated significant cash flows at the inception of the contracts. These agreements had contract prices that differed from market prices at closing, which resulted in cash payments to or from the counterparty at the acquisition of the contract. We paid net cash of $156.1 million in 2010 to acquire various contracts. During

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2009, we received net cash of $109.4 million due to the execution of total return swaps to assist in the execution of our divestitures of our international commodities and Houston-based gas trading operations. We reflect the underlying contracts on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether they were above- or below-market prices at closing; therefore, we have also reflected them on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year ended December 31,	**2010**	2009	2008
		(In millions)	
Financing activities proceeds from contract and portfolio acquisitions	**$ 52.2**	$ 2,263.1	$
Investing activities contract and portfolio acquisitions	**(208.3)**	(2,153.7)	
Cash flows from contract and portfolio acquisitions	**$ (156.1)**	$ 109.4	$

We record the proceeds we receive to acquire energy purchase and sale agreements as a financing cash inflow because it constitutes a prepayment for a portion of the market price of energy, which we will buy or sell over the term of the agreements and does not represent a cash inflow from current period operating activities. For those acquired contracts that are derivatives, we record the ongoing cash flows related to the contract with the counterparties as financing cash inflows. For those acquired contracts that are not derivatives, we record the ongoing cash flows related to the contract as operating cash flows.

We discuss certain of these contract and portfolio acquisitions in more detail in *Note 2 to Consolidated Financial Statements.*

Cash Flow Impacts CENG Joint Venture

Prior to November 6, 2009, we recorded 100% of the revenues, expenses, and cash flows from CENG and the nuclear plants it owns because we wholly owned this entity. On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG to EDF, and we deconsolidated CENG. Accordingly, for periods after November 6, 2009, we ceased recording CENG's cash flows and began to record cash flows from our PPA and other transactions with CENG. We will record any future cash flows from distributions received from CENG based on our 50.01% ownership interest, and we may be required to make capital contributions to help fund CENG's capital program.

As a result of deconsolidation, our Generation business cash flows differed from historical cash flows primarily due to the following factors:

- We now sell between 85-90% of the output of CENG's plants, excluding output sold by CENG directly to third parties, rather than 100% of the plants' total output including volumes contracted to third parties.
- Fuel and purchased energy expenses reflect our purchases of the output of CENG's plants, excluding output sold directly to third parties, as provided under the terms of the PPA with CENG. We discuss the terms, and subsequent amended terms, of the PPA in *Note 4 to Consolidated Financial Statements*.
- Operating expenses no longer include CENG's plant operating costs or general and administrative expenses.
- We no longer incur cash flows for 100% of CENG's capital expenditures or the acquisition of nuclear fuel, but we are required to make capital contributions to help CENG fund these expenditures.
- We will record cash distributions from CENG if and when such distributions are declared. We did not receive any distributions from CENG in 2010.

In addition, we entered into a power services agency agreement (PSA) and an administrative service agreement (ASA) with CENG. The PSA is a five-year agreement under which we will provide scheduling, asset management and billing services to CENG and will recognize average annual revenue of approximately $16 million.

The ASA is a one year agreement that is renewable annually under which we provided administrative support services to CENG for a fee of approximately $66 million for 2010. The level of fees for administrative support services will be subject to change in future years based on the level of services provided. The charges under these agreements are intended to represent the actual cost of the services provided to CENG from us. In October 2010, we entered into a comprehensive agreement with EDF. Among other provisions of the agreement, the ASA was extended through 2017. We discuss the comprehensive agreement with EDF in more detail in *Note 4 to Consolidated Financial Statements*.

Impact of Security Ratings on Our Liquidity

We rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. Independent credit rating agencies rate Constellation Energy's and BGE's fixed-income securities. These ratings affect how much it will cost us to sell securities and, in certain cases, our ability to access capital markets to sell securities. Generally, the better the rating, the lower the cost of the securities to us when we sell them. The factors that credit rating agencies consider in establishing Constellation Energy's and BGE's credit ratings include, but are not limited to, cash flows, liquidity, business risk profile, stock price volatility, political, legislative, and regulatory risk, interest charges relative to operating cash flows and the level of debt relative to total capitalization.

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At the date of this report, the senior unsecured debt and commercial paper credit ratings for Constellation Energy and BGE were as follows:

	Standard & Poor's Rating Group	Moody's Investors Service	Fitch Ratings
Constellation Energy			
Senior Unsecured Debt	BBB-	Baa3	BBB-
Commercial Paper	A-3	P-3	F3
BGE			
Senior Unsecured Debt	BBB+	Baa2	BBB+
Commercial Paper	A-2	P-2	F2

The Constellation Energy and BGE ratings in the above table reflect stable outlooks by all the credit rating agencies, except that Moody's rating of BGE reflects a positive outlook. If any of these credit ratings were to be downgraded, especially below investment grade, our ability to raise capital on favorable terms, including in the commercial paper markets, if available, 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. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade.

We discuss the potential effect of a ratings downgrade in the *Collateral* section.

We discuss the potential effect of a ratings downgrade on our ability to maintain ongoing compliance with financial ratios in our existing credit agreements in *Note 8 to Consolidated Financial Statements.*

As a condition to the October 2009 Maryland PSC order approving our transaction with EDF, Constellation Energy and BGE were required to implement "ring fencing" measures to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. We completed the implementation of these measures in February 2010.

We remain committed to maintaining a stable investment grade credit profile and to meeting our liquidity requirements. We discuss our available sources of funding in more detail below.

Available Sources of Funding

In addition to cash generated from operations, we rely upon access to capital for our capital expenditure programs and for the liquidity required to operate and support our commercial businesses. Our liquidity requirements are funded by credit facilities and cash. We fund our short-term working capital needs with existing cash and with our credit facilities, many of which support direct cash borrowings and the issuance of commercial paper. We also use our credit facilities to support the issuance of letters of credit, primarily for our NewEnergy business.

The primary drivers of our use of liquidity have been our capital expenditure requirements and collateral requirements associated with hedging our generating assets and hedging our NewEnergy business in both power and gas. Significant changes in the prices of commodities, depending on hedging strategies we have employed, could require us to post additional letters of credit, and thereby reduce the overall amount available under our credit facilities or to post additional cash, thereby reducing our available cash balance. Additional regulation of the derivatives markets could also require us to post additional cash collateral. We discuss the financial reform legislation enacted in 2010 in more detail in the *Federal Regulation* section.

We discuss our, and BGE's, credit facilities in detail in *Note 8 to Consolidated Financial Statements*.

Net Available Liquidity

Constellation Energy's (excluding BGE) and BGE's net available liquidity at December 31, 2010 was $3.3 billion and $0.6 billion, respectively. We discuss net available liquidity in more detail in the *Note 8 to Consolidated Financial Statements*.

Collateral

Constellation Energy's collateral requirements generally arise from its NewEnergy business as a result of its participation in certain organized markets, such as Independent System Operators (ISOs) or financial exchanges, as well as from our margining on over-the-counter (OTC) contracts.

To support NewEnergy's wholesale and retail power obligations and our limited trading activities, Constellation Energy posts collateral to ISOs. Forward hedging of our Generation and NewEnergy businesses creates the need to transact with exchanges such as New York Mercantile Exchange and Intercontinental Exchange. We post initial margin based on exchange rules, as well as variation margin related to the change in value of the net open position with the exchange.

In addition to the collateral posted to ISOs and exchanges, we post collateral with certain OTC counterparties. These collateral amounts may be fixed or may vary with price levels.

There are certain inherent asymmetries relating to the use of collateral that create liquidity requirements for our Generation and NewEnergy businesses. These asymmetries arise from our actions to be economically hedged, as well as market conditions or conventions for conducting business that result in some transactions being collateralized while others are not, including:

- In our NewEnergy business, we generally do not receive collateral under contractual obligations to supply power or gas to our customers but we hedge these transactions through purchases of power and gas that generally require us to post collateral. By entering into a gas supply agreement with the buyer of our gas trading operation, we have reduced our collateral requirements to support our retail gas operation. We discuss this gas supply agreement in more detail in *Note 4 to Consolidated Financial Statements*. We also intend to further align our load obligations by buying generation assets in regions where we do not have a significant generation presence and entering into longer-tenor agreements with merchant generators, further reducing our dependence on exchange-traded products, thereby

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lowering our collateral requirements. During 2010, we acquired generation assets in Texas, and in January 2011, we acquired generation assets in Massachusetts, which will assist with reducing our collateral requirements.

In our Generation business, we may have to post collateral on our power sale or fuel purchase contracts.

Finally, collateral types may asymmetrically impact our liquidity. In margining with OTC counterparties, we may post letter of credit (LC) collateral for an out-of-the money counterparty. However, we may receive LC collateral when we are in-the-money with a counterparty. Posting LCs reduces our liquidity while the receipt of LC collateral does not increase our liquidity.

Customers of our NewEnergy business rely on the creditworthiness of Constellation Energy. In this regard, we have certain agreements that contain provisions that would require us to post additional collateral upon a credit rating downgrade in the senior unsecured debt of Constellation Energy. Based on contractual provisions at December 31, 2010, we estimate that if Constellation Energy's senior unsecured debt were downgraded to one level below the investment grade threshold we would have the following additional collateral obligations:

Credit Ratings Downgraded to (1)	Level Below Current Rating	Additional Obligations (2)
	(In billions)	
Below investment grade	1	$ 1.0

(1) *If there are split ratings among the independent credit rating agencies, the lowest credit rating is used to determine our incremental collateral obligations.*

(2) *Includes $0.1 billion related to derivative contracts as discussed in Note 13 to Consolidated Financial Statements.*

Based on market conditions and contractual obligations at the time of a downgrade, we could be required to post additional collateral in an amount that could exceed the obligation amounts specified above, which could be material. We discuss our credit facilities in the *Available Sources of Funding* section. In addition, rulemaking under the Dodd-Frank Act could impose additional collateral requirements. We discuss this rulemaking in the *Federal Regulation* section.

Capital Resources

Our actual consolidated capital requirements for the years 2008 through 2010, along with the estimated annual amount for 2011, are shown in the following table.

We will continue to have cash requirements for:

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

Capital requirements for 2011 and 2012 include estimates of spending for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

- regulation, legislation, and competition,
- BGE load requirements,

environmental protection standards,

the type and number of projects selected for construction or acquisition,

the effect of economic and market conditions on those projects,

the cost and availability of capital,

potential capital contributions to CENG,

the availability of cash from operations, and

business decisions to invest in capital projects.

Our estimates are also subject to additional factors.

Please see the *Forward Looking Statements* and *Item 1A. Risk Factors* sections.

	2008	2009	2010	2011 (Estimate)
		(In billions)		
Generation and Other Capital Requirements:				
Major Environmental	$ 0.5	$ 0.3	$ 0.1	$ 0.1
Maintenance	0.5	0.6	0.1	0.1
Growth	0.4	0.2	0.1	
Total Generation and Other Capital Requirements	1.4	1.1	0.3	0.2
NewEnergy Capital Requirements:				
Maintenance	0.1			
Growth	0.2	0.1	0.1	0.2
Total NewEnergy Capital Requirements	0.3	0.1	0.1	0.2
Regulated Capital Requirements:				
Electric / Gas Distribution	0.4	0.3	0.4	0.4
Electric Transmission	0.1		0.1	0.1
Smart Energy Savers^{SM} Initiatives		0.1	0.1	0.1
Total Regulated Capital Requirements	0.5	0.4	0.6	0.6
Total Capital Requirements	$ 2.2	$ 1.6	$ 1.0	$ 1.0

Eligible capital projects are shown net of anticipated investment tax credits or grants.

As of the date of this report, we estimate our 2012 capital requirements will be approximately $1.0 billion.

Capital Requirements

Generation and NewEnergy Businesses

Our Generation and NewEnergy businesses' capital requirements consist of its continuing requirements, including expenditures for:

maintenance and uprates to the capacity of our generating plants,

solar projects and upstream natural gas properties,

- costs of complying with the Environmental Protection Agency (EPA), Maryland, and various other states' environmental regulations and legislation, and
- enhancements to our information technology infrastructure.

In addition, in January 2011, we completed the acquisition of Boston Generating's 2,950 MW fleet of generating plants for approximately $1.1 billion, subject to a working capital adjustment. We funded this acquisition through a mix of available cash and debt.

In December 2009, we were selected by the State of Maryland to construct, own, operate and maintain a 17 MW solar photovoltaic power installation in Emmitsburg, Maryland. We expect this project to cost us approximately $60 million and be completed by December 2012. Renewable electricity produced by the system will be purchased by the State of Maryland at the site of Mount St. Mary's University under a 20-year solar power purchase agreement.

In 2009, we acquired the 70 MW Criterion wind project to be constructed in Garrett County, Maryland. We closed this transaction in the first quarter of 2010 and we placed it in service in the fourth quarter of 2010.

Regulated Electric and Gas

Regulated electric and gas construction expenditures primarily include new business construction needs and improvements to existing facilities, including projects to improve reliability and support demand response and conservation initiatives. Further, BGE continues to invest in transmission projects that earn a FERC authorized rate of return.

In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of approximately $480 million. In 2009, the United States Department of Energy (DOE) selected BGE as a recipient of $200 million in federal funding for our smart grid and other related initiatives. This grant allows BGE to be reimbursed for smart grid and other expenditures up to $200 million, substantially reducing the total cost of these initiatives.

Funding for Capital Requirements

Generation and NewEnergy Businesses

We expect to fund the capital requirements of our Generation and NewEnergy businesses with internally generated cash and other available sources. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the money markets, capital markets and lease markets, subject to credit conditions and market liquidity, and, if necessary, from draw downs on credit facilities.

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

Regulated Electric and Gas

We expect to fund capital expenditures associated with our regulated electric and gas businesses through a combination of internally and externally generated cash. To the extent that internally generated cash is not sufficient to meet those requirements, we would seek additional funding from the short-term and long-term capital markets (including trust preferred securities or preference stock), subject to credit conditions and market liquidity, and, if necessary, from draw downs on credit facilities. BGE may also receive equity contributions from time to time from Constellation Energy.

Contractual Payment Obligations and Committed Amounts

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

We detail our contractual payment obligations as of December 31, 2010 in the following table:

	Payments				
	2011	2012-2013	2014-2015	Thereafter	Total
	(In millions)				
Contractual Payment Obligations					
Long-term debt: (1)					
Nonregulated					
Principal	$ 223.6	$ 19.7	$ 596.2	$ 1,774.9	$ 2,614.4
Interest	139.0	281.3	277.7	2,807.6	3,505.6
Total	362.6	301.0	873.9	4,582.5	6,120.0
BGE					
Principal	81.7	639.1	144.9	1,277.9	2,143.6
Interest	127.6	231.3	162.5	1,174.2	1,695.6
Total	209.3	870.4	307.4	2,452.1	3,839.2
BGE preference stock				190.0	190.0
Operating leases (2)					
Operating leases, gross	202.1	328.0	301.4	108.3	939.8
Sublease rentals	(22.4)	(41.7)	(19.6)	(28.6)	(112.3)
Operating leases, net	179.7	286.3	281.8	79.7	827.5
Purchase obligations: (3)					
Purchased capacity and energy (4)	430.6	503.0	164.3	263.6	1,361.5
Purchased energy from CENG (5)	488.4	1,761.2	1,735.5		3,985.1
Fuel and transportation	535.7	449.9	250.2	176.0	1,411.8
Other	53.0	30.0	7.5	5.4	95.9
Other noncurrent liabilities:					
Uncertain tax positions liability	60.3	100.2	5.5	4.0	170.0
Pension benefits (6)	7.2	160.6	92.2		260.0
Postretirement and post employment benefits (7)	26.8	55.5	58.5	249.1	389.9
Total contractual payment obligations	$2,353.6	$4,518.1	$3,776.8	$ 8,002.4	$18,650.9

(1) *Amounts in long-term debt reflect the original maturity date. Investors may require us to repay $75.0 million early through remarketing features. Interest on variable rate debt is included based on forward curve for interest rates.*

(2) *Our operating lease commitments include future payment obligations under certain power purchase agreements as discussed further in Note 11 to Consolidated Financial Statements.*

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

(4)

Our contractual obligations for purchased capacity and energy are shown on a gross basis for certain transactions, including both the fixed payment portions of tolling contracts and estimated variable payments under unit-contingent power purchase agreements.

(5) *As part of reaching a comprehensive agreement with EDF in October 2010, we modified our existing power purchase agreement with CENG to be unit contingent through the end of its original term in 2014. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, we agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. We have included in the table our commitments under this agreement for five years, the time period for which we have more reliable data. Further, we continue to own a 50.01% membership interest in CENG that we account for as an equity method investment. See Note 16 in the Consolidated Financial Statements for more details on this agreement.*

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

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

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Off-Balance Sheet Arrangements

For financing and other business purposes, we utilize certain off-balance sheet arrangements that are not reflected in our Consolidated Balance Sheets. Such arrangements do not represent a significant part of our activities or a significant ongoing source of financing.

We use these arrangements when they enable us to obtain financing or execute commercial transactions on favorable terms. As of December 31, 2010, we have no material off-balance sheet arrangements, including:

- guarantees with third parties that are subject to initial recognition and measurement requirements,
- retained interests in assets transferred to unconsolidated entities or similar arrangement that serves as credit, liquidity or market risk support to such entity for such asset,
- derivative instruments indexed to our common stock, and classified as equity, or
- variable interests in unconsolidated entities that provide financing, liquidity, market risk, or credit risk support, or engage in leasing, hedging or research and development services.

At December 31, 2010, Constellation Energy had a total face amount of $9.4 billion in guarantees outstanding, of which $8.6 billion related to our NewEnergy business. These amounts generally do not represent incremental consolidated Constellation Energy obligations; rather, they primarily represent parental guarantees of certain subsidiary obligations to third parties in order to allow our subsidiaries the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Our estimated net exposure for obligations under commercial transactions covered by these guarantees was approximately $1.5 billion at December 31, 2010, which represents the total amount the parent company could be required to fund based on December 31, 2010 market prices. For those guarantees related to our derivative liabilities, the fair value of the obligation is recorded in our Consolidated Balance Sheets. We believe it is unlikely that we would be required to perform or incur any losses associated with guarantees of our subsidiaries' obligations.

We discuss our other guarantees in *Note 12 to Consolidated Financial Statements* and our significant variable interests in *Note 4 to Consolidated Financial Statements*.

Risk Management

Introduction

Risk is inherent in our business activities. Constellation Energy is exposed to market, credit, operational, and liquidity risks that are fundamental to our business of providing products and services across the energy value chain. Additionally, our businesses are subject to business and strategic risks, the risks of unsuccessful business performance due to changing economic conditions, competition, regulatory environment, legislation, economic conditions, market liquidity, country or sovereign issues, systems or process failure, and fiscal and monetary policies. These risks exist in our business with varying levels of exposure, and are interrelated and cannot be managed in isolation.

The Company's risk management framework and governance structure are intended to provide appropriate controls and ongoing management of the major risks in our business activities. The risk management framework is also intended to create a culture of risk awareness and personal accountability for risk-taking across the Company. As a result of the extent and diversity of the risks the Company faces in its business operations, we analyze risk and risk concentration at transaction, portfolio, business, and enterprise-wide levels to ensure that material risks are identified and managed effectively. We utilize numerous methods to evaluate and measure risks. In general, we evaluate risks in terms of the impact on our economic value, earnings, liquidity, strategic objectives, credit rating, reputation, and values. We identify and evaluate risks based not only on their probability of occurring and magnitude of impact on the financial statements, but also with respect to the potential for significant or unexpected shifts in market conditions or rules.

We recognize the importance of managing risk as a key differentiator in the energy business and view the active and effective management of the risks in our businesses to be of paramount importance. Our risk management program is based on established policies and procedures to manage risks, combined with an extensive system of internal controls. Nevertheless, no system of risk management can cost-effectively eliminate all risks to which an entity is exposed. Thus, in particular environments, the Company may not be able to mitigate risk exposures to the level desired and may have exposures to certain risk factors that cannot be mitigated.

In this section, we will review the Company's risk practices in terms of our:

- risk governance,
- risk functions, and
- risk exposures.

Risk Governance

Our Board of Directors is responsible for risk oversight of Company activities. The Board of Directors has approved the Company's risk appetite statement and has authorized management to establish risk policies and limits consistent with this statement. The Audit Committee of the Board of Directors periodically reviews compliance with our risk policies and limits and the effectiveness of the related internal controls. The Compensation Committee of the Board of Directors is responsible for oversight of the impact of compensation policies on risk-taking. Management has established the risk appetite statement in the context of the market environment and the Company's business strategy. In setting the risk appetite, the Company takes into consideration factors such as market volatility, product liquidity, business trends, and management experience.

The Company's Risk Management Committee (RMC) is responsible for approving risk management policies and limits consistent with the risk appetite statement, reviewing procedures for the identification, assessment, measurement, and

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management of risks, and monitoring risk exposures. The RMC meets on a regular basis and is chaired by our Chief Executive Officer. Other committee members are our Chief Risk Officer, Chief Financial Officer, Vice Chairman, General Counsel, Chief Human Resources Officer, head of Corporate Strategy and Development, head of Corporate Affairs, Public, and Environmental Policy and business unit leaders. In addition, the Chief Risk Officer coordinates with the risk management committees in the business units that meet regularly to identify, assess, and quantify material risk issues and to develop strategies to manage these risks.

Business managers are responsible for managing risks within the established risk appetite, while the Risk Management Group (RMG) is responsible for enforcing compliance with risk management policies and risk limits. The RMG reports to the Chief Risk Officer, who is a member of the Company's Management Committee and who reports to the Chief Executive Officer and the Board of Directors. The Chief Risk Officer provides regular risk management updates to the Audit Committee and the Board of Directors.

In an effort to manage risks, Constellation Energy has established a series of limits at the corporate and business unit level that reflect the Company's risk appetite. Business units are responsible for adhering to established limits, against which exposures are monitored and reported. Limit breaches are reported in a timely manner to senior management, who consults with the business unit on an appropriate course of action.

Risk Functions

Risks are managed at the individual and portfolio level of exposure in each business relative to the Company's risk appetite in aggregate and across all major risk types.

Constellation Energy's RMG is an independent function tasked with providing an independent quantification and assessment of key business risks, as well as providing an evaluation of individual risk components that contribute to the Company's consolidated risk profile. The RMG is also responsible for establishing risk policies, maintaining appropriate risk controls, ensuring compliance with policies and procedures, and monitoring methods according to the risk parameters established by the Board of Directors.

The RMG consists of seven divisions that focus on a specialized area of risk.

Credit Risk Management

Credit Risk Management is responsible for managing the risk of loss inherent in the business units stemming from counterparty or customer failures and adverse market events that effect counterparty creditworthiness. This group supports the business units by establishing credit relationships with various wholesale counterparties and retail customers and facilitating market liquidity with credit limits and appropriate contractual credit terms and conditions. Credit risk managers are responsible for managing credit risk associated with our business activities, including establishing limits and contractual structures, as well as establishing and enforcing credit policies.

Market Risk Management

Market Risk Management is responsible for effectively identifying, quantifying, monitoring, and reporting on impacts of market risk, to include price volatility, correlations, volume uncertainty, market liquidity, interest rate and currency exposure on company businesses. The market risk group also enforces the Market Risk policies and ensures compliance with these policies, including the monitoring, analyzing, and escalating of market risk controls. This group also develops market risk measurement tools, such as stress and scenario tests, gross margin-at-risk, and assists the businesses in implementing market strategies with the highest benefits.

Collateral and Funding Liquidity Risk Management

Collateral Risk Management is responsible for providing an integrated view on credit, market, and company liquidity risks to facilitate Treasury's management of the Company's collateral and overall liquidity position. Funding liquidity risk is the risk that we may be unable to fund our obligations in some future period. This group's responsibilities include measuring and monitoring collateral flows, downgrade collateral needs, and collateral use across the Company. Additionally, this group forecasts expected collateral and liquidity requirements as well as estimates potential collateral requirements due to market shifts, hedging strategies, and adjustments to the Company's credit ratings. Finally, Collateral Risk Management assists the businesses in determining the strategic use of collateral and the appropriate cost of collateral for transactions. The group also works closely with the Treasury function to plan for expected and contingent liquidity needs based on the Company's long-term business plan.

Operational Risk Management

Operational risk is the risk associated with human error, a failure of process and systems or external factors. RMG staff oversee implementation of a common framework for defining, measuring, monitoring, and reporting operational risks. The integrated risk assessment process involves capturing risk and controls holistically. Accountability for the identification of risks in our business processes resides with business management, who must ensure the completeness and effectiveness of controls and level of residual risk.

Corporate Audit

Corporate Audit assists in ensuring that controls put in place by management to mitigate the risks of the business are adequate and functioning appropriately. This group supports the risk assessment process including the analysis of inherent and residual risk, performs risk-based audits as approved by the Audit Committee of the Board of Directors, and supports the improvement of the effectiveness and efficiency of key business processes.

Special Situations Group

Our Special Situations Group is comprised of two departments: receivables management and credit workout. Receivables management seeks to maximize cash flows from collection efforts for the Company's business units. Its primary function is to mitigate risk by focusing efforts on all aspects of the accounts receivable process including fees related to early termination of energy supply contracts. Credit workout is responsible for the management of distressed customers. These include counterparties in bankruptcy and contractual default. Credit workout also seeks to generate cash flows by negotiating early settlement on potential losses and through the sale of impaired assets in the secondary market.

Deal Review, Risk Analytics and Risk Capital

Our Deal Review team performs independent reviews of structured transactions and develops standardized risk-adjusted metrics for assessing these transactions. Our Risk Analytics team provides quantitative support to all risk functions, builds key risk models and metrics, and conducts independent validation of models used by the Company. Our Risk Capital team is responsible for the development and implementation of a framework for the measurement of capital adequacy, risk-based transaction pricing and risk-adjusted performance measurement of our business segments and portfolios. Risk capital, or economic capital, is the level of capital required to offset the effect of unexpected specified stress on the economic value of the Company. It is an assessment of the underlying market, credit, operational, and liquidity risks of the Company's business activities, utilizing internal risk assessment methodologies.

Risk Exposures

We manage risks across all of our businesses. We summarize below the risks we manage within each of our businesses.

Generation and NewEnergy Businesses

Our Generation and NewEnergy businesses are exposed to various risks in the competitive marketplace that may materially impact our financial results and affect our earnings. These risks include changes in commodity prices, potential imbalances in supply and demand, credit risk and operational risk.

Regulated Electric Business

BGE does not own or operate any electric generating facilities. Therefore, BGE's regulated electric business is exposed to market price risk. To mitigate this, BGE obtains energy and capacity to provide SOS through a competitive bidding process approved by the Maryland PSC. We discuss SOS and the impact on base rates in more detail in *Item 1. Business Baltimore Gas and Electric Company Electric Business* section. As a result of this process, BGE's exposure to market price risk is limited, and at December 31, 2010, our exposure to commodity price risk for our regulated electric business was not material. However, BGE may enter into electric futures, options, and swaps to hedge its market price risk if appropriate. We discuss this further in *Note 13 to Consolidated Financial Statements*.

BGE's regulated electric business is also exposed to wholesale credit risk from its suppliers as well as retail credit risk from its customers. Finally, BGE is subject to operational risks, including potential impacts from storms and distribution asset failures.

Regulated Gas Business

BGE acquires all of its natural gas for delivery to customers from third party suppliers. Therefore, BGE's regulated gas business is exposed to market price risk. However, BGE recovers the costs of purchased gas under the market-based rates incentive mechanism approved by the Maryland PSC. Additionally, BGE may enter into gas futures, options, and swaps to hedge its price risk under our market-based rate incentive mechanism and our off-system gas sales program as appropriate. We discuss this further in *Note 13 to Consolidated Financial Statements*. At December 31, 2010, our exposure to commodity price risk for our regulated gas business was not material.

BGE's regulated gas business is also exposed to wholesale credit risk from its suppliers as well as retail credit risk from its customers. Finally, BGE is subject to operational risks, including potential impacts from storms and distribution asset failures.

Risk Exposure Categories

The various categories of risk exposures that we manage include, but are not limited to, market risk, which includes interest rate risk, security price risk, and foreign currency risk; credit risk, which includes wholesale and retail credit risk; operational risk and collateral and funding liquidity risk. As previously noted, these risks may be common to more than one of our businesses. We discuss each of these primary risk exposure categories separately below.

Market Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of power, natural gas, coal, and other related commodities. These risks arise from our ownership and operation of power plants, our retail and wholesale customer supply operations, and our origination, risk management, and trading activities. These commodity price risks arise from:

- changes in market volatilities or correlations, and
- changes in interest and foreign exchange rates.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. We use such commodities and products in our Generation and NewEnergy businesses, and if we do not hedge the associated financial exposure, this commodity price volatility could adversely affect our economic value or earnings. These factors include:

- seasonal, daily, and hourly changes in demand,
- extreme peak demands due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- location of our generating facilities relative to the location of our load-serving obligations,
- procedures used to maintain the integrity of the physical power system during extreme conditions,
- changes in the nature and extent of federal and state regulations, and
- geopolitical concerns affecting global supply of coal, oil, and natural gas.

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

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

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

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

Power, gas, coal, and other related commodity trading risks involve the potential decline in net income or financial condition due to adverse changes in market prices, whether arising from customer activities, generating plants, or proprietary positions taken by the Company. We assess and monitor market risk with a variety of tools, including EVaR, VaR, scenario analysis, and stress testing.

EVaR:

EVaR measures the potential pre-tax loss in the fair value of the Generation and NewEnergy businesses due to changes in market risk factors. EVaR is a one-day value-at-risk measure calculated at a 95% confidence level assuming a standard normal distribution of prices over the most recent rolling 3-month period. EVaR includes all positions over a forward rolling 60-month time horizon that expose us to market price risk, regardless of business line.

Positions included in EVaR are comprised of mark-to-market and nonderivative accrual positions that create market risk including:

- derivative and nonderivative commodity contracts associated with our Generation and NewEnergy businesses,
- physical assets, such as our owned and contractually controlled generating plants,
- our share of investments in generating plants, and
- our share of investments in upstream natural gas properties.

We include the positions related to physical assets to provide a more complete presentation of our commodity market risk exposures. EVaR includes illiquid products and positions for which there is limited price discovery. Modeling the positions in our Generation and NewEnergy businesses involves a number of assumptions, and includes projections of generation, emission rates and costs, customer load growth, load response to weather, and customer response to competitive supply. Changes in our forecast or management estimates will affect the fair value of these positions in a manner not captured by EVaR.

EVaR reflects the risk of loss due to market prices under normal market conditions. An inherent limitation of our value-at-risk measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from the past. We use stress tests and scenario analysis to better understand extreme events as a complement to EVaR. This includes exposure to unlikely but plausible events in abnormal markets, sensitivity to changes in management projections of customer demand or forecasted generation output, and price sensitivity to illiquid points and regional basis spreads.

EVaR is monitored daily and is subject to regional and overall guidelines for the NewEnergy business. We place guidelines on the risk associated with illiquid delivery locations and regional basis within our NewEnergy business. Additionally, we monitor generation plant hedge ratios relative to guidelines specified by management. Stress tests and scenario analysis are conducted regularly and the results, trends, and explanations are reviewed by senior management and risk committees.

The EVaR amounts below represent the potential pre-tax change in the fair values of our Generation and NewEnergy businesses positions over a one-day holding period.

EVaR

For the year ended December 31,	**2010**	2009
	(In millions)	
95% Confidence Level, One-Day Holding Period		
Year end	**$ 36.3**	$ 73.0
Average	**52.2**	92.8
High	**71.6**	122.8
Low	**34.4**	64.1

At December 31, 2010, our EVaR was approximately $36.3 million, which represents a 50% decline from its level of $73 million on December 31, 2009, mainly due to lower price levels and lower volatilities as well as a decrease in our ownership of nuclear generation as a result of our 2009 sale of a 49.99% membership interest in CENG to EDF.

VaR:

VaR measures the potential pre-tax loss in the fair value of mark-to-market energy contracts due to changes in market risk factors. VaR is calculated assuming a standard normal distribution of prices over the most recent rolling 3-month period. VaR includes all positions subject to mark-to-market accounting, including not only contracts that hedge the economics of NewEnergy nonderivative power and fuel contracts and which do not receive hedge accounting treatment, but also contracts designated for trading. Thus, the positions for which we monitor VaR are included within, and are not incremental, to the positions subject to EVaR.

VaR and EVaR have similar limitations. VaR may include some products and positions for which there is limited price discovery or market depth. The modeling of option positions

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included in VaR involves a number of assumptions and approximations. An inherent limitation of our VaR measures is the reliance on historical prices. A sudden shift in market conditions can cause the future behavior of market prices to differ materially from that of the past.

The VaR amounts below represent the potential pre-tax loss in the fair value of our NewEnergy business positions subject to mark-to-market accounting, including both trading and non-trading activities, over one and ten-day holding periods.

Total Mark-to-Market VaR

For the year ended December 31,	**2010**	2009
	(In millions)	
99% Confidence Level, One-Day Holding Period		
Year end	**$ 13.6**	$ 8.0
Average	**7.3**	18.1
High	**13.8**	55.5
Low	**4.8**	5.0
95% Confidence Level, One-Day Holding Period		
Year end	**$ 10.4**	$ 6.1
Average	**5.6**	13.8
High	**10.5**	42.2
Low	**3.6**	3.8
95% Confidence Level, Ten-Day Holding Period		
Year end	**$ 32.9**	$ 19.2
Average	**17.7**	43.7
High	**33.2**	133.6
Low	**11.4**	12.0

Constellation Energy's proprietary trading activities are substantially reduced from previous years and remain immaterial. These activities continue to be managed with daily VaR limits, stop loss limits and position limits.

Interest Rate Risk

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

As of December 31, 2010, we have interest rate swaps relating to $400.0 million of our long-term debt. These fair value hedges effectively convert our current fixed-rate debt to a floating-rate instrument tied to the three month London Inter-Bank Offered Rate (LIBOR). Including the $400.0 million in interest rate swaps, approximately 11.1% of our long-term debt is floating-rate.

During January 2011, as part of retiring the remainder of our 7.00% Notes, we terminated $200.0 million of interest rate swaps.

During February 2011, we entered into $500 million of interest rate swaps related to fixed rate long-term debt, effectively converting the debt to a floating-rate instrument tied to LIBOR. Of these swaps, $350 million qualify for and have been designated as fair value hedges and $150 million do not qualify as fair value hedges and will be marked to market through earnings.

We discuss our use of derivative instruments, including interest rate swaps, to manage our interest rate risk in more detail in *Note 13 to Consolidated Financial Statements*.

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

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2011	2012	2013	2014	2015	Thereafter	Total	Fair value at December 31, 2010
				(Dollars in millions)				
Long-term debt								
Variable-rate debt	$ 209.6	$ 18.0	$	$	$ 226.2	$ 74.9	$ 528.7	$ 528.7
Average interest rate (A)	1.24%	4.50%	%	%	2.36%	2.13%	1.95%	
Fixed-rate debt	$ 95.7	$ 174.2	$ 466.6	$ 90.4	$ 424.5	$ 2,977.9	$ 4,229.3	$ 4,518.4
Average interest rate	6.10%	6.37%	6.06%	5.33%	4.75%	6.60%	6.31%	

(A)
Interest on variable rate debt is included based on the forward curve for interest rates at December 31, 2010.

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Security Price Risk

We are exposed to price fluctuations in financial markets primarily through our pension plan assets. In 2010, our actual gain on pension plan assets was $148.8 million. We describe our pension funding requirements in more detail in *Note 7 to Consolidated Financial Statements*.

Foreign Currency Risk

Our Generation and NewEnergy businesses are exposed to the impact of foreign exchange rate fluctuations. This foreign currency risk arises from our activities in countries where we transact in currencies other than the U.S. dollar. In 2010, our exposure to foreign currency risk was not material. We manage our exposure to foreign currency exchange rate risk using a foreign currency hedging program. We will continue to have limited exposure to the Canadian dollar due to our Canadian gas and power operations.

Credit Risk

We are exposed to credit risk through our Generation and NewEnergy businesses and BGE's operations. Credit risk is the loss that may result from counterparties' nonperformance and retail customer accounts receivable and forward value payment risk arising from contracted power and gas supply agreements. We evaluate our credit risk as discussed below.

Wholesale Credit Risk

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

As of December 31, 2010, our total exposure across our entire wholesale portfolio is $2.5 billion, net of collateral, and includes accrual positions and derivatives. This total exposure has declined from the $2.8 billion as of December 31, 2009, primarily driven by a change in commodity prices and the decrease in our exposure to CENG throughout 2010.

The top ten counterparties account for 55% of our total exposure with none of that exposure being non-investment grade. We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of total credit exposure. At December 31, 2010, two counterparties, a large power cooperative and CENG, comprised a total exposure concentration of 25%.

As of December 31, 2010 and 2009, counterparties in our NewEnergy credit portfolio had the following public credit ratings, shown as a percentage of the total portfolio exposure:

At December 31,	**2010**	**2009**
Rating		
Investment Grade (1)	**47%**	43%
Non-Investment Grade	**4**	2
Not Rated	**49**	55

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

Our exposure to "Not Rated" counterparties was $1.2 billion at December 31, 2010 compared to $1.5 billion at December 31, 2009. This decrease was mostly driven by a reduction in our CENG credit exposure, which is not externally rated.

Many of our not rated counterparties (including CENG) are considered investment grade equivalent based on our internal credit ratings. We utilize internal credit ratings to evaluate the creditworthiness of our wholesale customers, including those companies that do not have public credit ratings. Based on internal credit ratings, approximately $1.1 billion or 87% of the exposure to "Not Rated" counterparties was rated investment grade equivalent at December 31, 2010 and approximately $1.2 billion or 81% was rated investment grade equivalent at

December 31, 2009.

The following table provides the breakdown of the credit quality of our wholesale credit portfolio based on our internal credit ratings. This includes those counterparties which are externally rated and those in the "Not Rated" category as a percentage of the total portfolio exposure.

At December 31,	**2010**	**2009**
Investment Grade Equivalent	**89%**	88%
Non-Investment Grade Equivalent	**11**	12

If a counterparty were to default on its contractual obligations and we were to liquidate transactions with that entity, our potential credit loss would include all forward and settlement exposure plus any additional costs related to termination and replacement of the positions. This would include contracts accounted for using the mark-to-market, hedge, and accrual accounting methods, the amount owed or due from settled transactions, less any collateral held from the counterparty. In addition, if a counterparty were to default under an accrual contract that is currently favorable to us, we may recognize a material adverse impact on our results in the future delivery period to the extent that we are required to replace the contract that is in default with another contract at current market prices. These potential losses would be limited to the extent that the in-the-money amount exceeded any credit mitigants such as cash, letters of credit, or parental guarantees supporting the counterparty obligation. To reduce our credit risk with counterparties, we attempt to enter into agreements that allow us to obtain collateral on a contingent basis, seek third party guarantees of the counterparty's obligation, and enter into netting agreements that allow us to offset receivables and payables with forward exposure across many transactions.

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

We also enter into various wholesale transactions through ISOs. These ISOs are exposed to counterparty credit risks. Any losses relating to counterparty defaults impacting the ISOs are allocated to and borne by all other market participants in the ISO. These ISOs have established credit policies and practices to mitigate the exposure of counterparty credit risks. As a market participant, we continuously assess our exposure to the credit risks of each ISO.

BGE is exposed to wholesale credit risk of its suppliers for electricity and gas to serve its retail customers. BGE may receive performance assurance collateral to mitigate electricity suppliers' credit risks in certain circumstances. Performance assurance collateral is designed to protect BGE's potential exposure over the term of the supply contracts and will fluctuate to reflect changes in market prices. In addition to the collateral provisions, there are supplier "step-up" provisions, where other suppliers can step in if the early termination of a full-requirements service agreement with a supplier should occur, as well as specific mechanisms for BGE to otherwise replace defaulted supplier contracts. All costs incurred by BGE to replace the supply contract are to be recovered from the defaulting supplier or from customers through rates.

Retail Credit Risk

We are exposed to retail credit risk through our NewEnergy electricity and natural gas supply activities, which serve commercial and industrial companies and governmental entities, and through BGE's electricity and natural gas distribution operations. Retail credit risk results when customers default on their contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers of our nonregulated retail businesses.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures, and the use of credit mitigation measures such as letters of credit or prepayment arrangements. In addition, we have taken steps to augment our credit staff in response to current economic conditions. In accordance with our credit policy we do not have a significant exposure concentration with any one customer, geographic area or industry.

Retail credit quality is dependent on the economy and the ability of our customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, our retail credit risk may be adversely impacted. However, we have organized a dedicated credit workout function whose job is to work with distressed customers and recover receivables owed to the company. This also involves negotiating early termination settlements and selling impaired assets in the secondary market.

BGE is subject to retail credit risk associated with both the delivery portion of a customer's bill as well as the uncollectible expense or credit risk from the gas and/or electric commodity portion of the bills of those customers to whom BGE sells the gas and electric commodity. BGE is also exposed to credit risk associated with the timing of the collection of receivables from those customers who have contracted with a third party supplier where BGE has purchased that supplier's receivables. Although both BGE's delivery and commodity rates include some level of costs for uncollectible customer accounts receivable expenses, full recovery is contingent on amounts approved by the Maryland PSC in customer rates and, therefore is not guaranteed and BGE is exposed to these potential losses and related carrying costs.

Operational Risk

Operational risk is the risk associated with human error or a failure of process and systems, or external factors, as well as the risk of operating owned and contractually controlled generating assets, electric transmission and distribution systems, and gas distribution systems. We are exposed to many types of operational risks, including fraud by employees, clerical and record-keeping errors, and unauthorized data access. Additionally, our asset operations can be effected by those events that are partially or wholly out of our control, like natural disasters, acts of terrorism, and computer application viruses, which may cause losses in generation or service to customers resulting in revenue loss.

We own, have ownership interests in, and operate power generation facilities, which use a diverse mix of fuels including fossil fuels, nuclear and biomass. We are also exposed to variations in the prices for, and required volumes of, natural gas, oil, and coal required to fuel our power plants that generate electricity. Therefore, high commodity prices increase the impact of generator outages and variable load, but as long as the electricity and fuel prices move in tandem, we have limited exposure to changing commodity prices. During periods of high demand on our generation assets, our fuel supplies may be insufficient and could require us to procure additional fuel at higher prices. Alternatively, during periods of low demand on our generation assets, our fuel supplies may exceed our needs, and could result in us selling the excess. These scenarios could potentially lead to a material adverse impact on our financial results.

We are exposed to risk on both sides of the distribution chain, from fuel to end customer delivery, due to inability to produce energy. If one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed-price sales commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices. In addition, we are exposed to the risk that available sources of supply may differ from the amount of power demanded by our customers under fixed-price load-serving contracts. During periods of high demand, our power supplies may be insufficient to serve our customers' needs and could require us to purchase additional energy at higher prices. Alternatively, during periods of low demand, our electricity supplies may exceed our customers' needs and potentially result in selling excess energy at lower prices. This could have a material adverse impact on our financial results.

Collateral and Funding Liquidity Risk

Funding liquidity risk relates to the ability to fund current and future obligations of the company given variability in collateral requirements as well as variability around working capital requirements and other cash flows that may affect our liquidity. To assess funding liquidity risk, we distinguish between sources and uses of liquidity. Sources of liquidity include projected net available cash and the unused capacity available from our credit facilities. Uses include expected and contingent collateral requirements as well as any unexpected variation of cash flows from projected levels. We define contingent requirements to be any incremental or decremental requirements to expected requirement levels.

To manage liquidity risk, we quantify sources of liquidity and the expected and contingent uses of liquidity both over a short-term and long-term horizon. Contingent uses of liquidity are determined by stress-testing our portfolio using a simulation of extreme, adverse price stresses and measuring their combined impact on collateral needs and on cash flows related to losses due to market and credit risk. Liquidity stresses related to operational risks (weather, plant outages) and other business risks not directly linked to price moves are assessed on a regular basis using scenario analysis. Results of the liquidity assessment are shared regularly with senior management.

Liquidity risk assessment has been integrated into our strategic planning process. Expected and contingent funding needs implied by the business plans of our various business units are first aggregated and compared to available liquidity sources over the planning horizon. Capital and liquidity sources are then allocated to business units based on their business plans, taking into account the cost of providing liquidity. We believe that this integrated view on sources and uses of liquidity allows us to ensure proper funding of the business in accordance with our business plan.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

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Item 8. Financial Statements and Supplementary Data

REPORTS OF MANAGEMENT

Financial Statements

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

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

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

Management's Report on Internal Control Over Financial Reporting Constellation Energy Group, Inc.

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

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

The management of Constellation Energy conducted an evaluation of the effectiveness of Constellation Energy's internal control over financial reporting using the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that Constellation Energy's internal control over financial reporting was effective as of December 31, 2010.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the effectiveness of Constellation Energy's internal control over financial reporting as of December 31, 2010, as stated in their report on the next page.

Mayo A. Shattuck III	Jonathan W. Thayer
Chairman of the Board, President and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

Management's Report on Internal Control Over Financial Reporting Baltimore Gas and Electric Company

The management of Baltimore Gas and Electric Company (BGE), under the direction of its principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rule 13a-15(f).

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

The management of BGE conducted an evaluation of the effectiveness of BGE's internal control over financial reporting using the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance to management and the Board of Directors regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that BGE's internal control over financial reporting was effective as of December 31, 2010.

This annual report does not include an attestation report of BGE's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by BGE's independent registered public accounting firm pursuant to an exemption for non-accelerated filers set forth in the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Kenneth W. DeFontes, Jr.	Carim V. Khouzami
President and Chief Executive Officer	*Chief Financial Officer and Treasurer*

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REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and its subsidiaries (the Company) at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, the financial statement schedule and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in *Note 1* to the consolidated financial statements, in 2010 the Company changed its method of accounting for and presenting variable interest entities. As discussed in *Note 13* to the consolidated financial statements, in 2008 the Company changed its method of accounting for the measurement of fair value and classifying certain collateral balances.

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

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

PricewaterhouseCoopers LLP
Baltimore, Maryland
March 1, 2011

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

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) (1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and its subsidiaries (the Company) at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in *Note 1* to the consolidated financial statements, in 2010 the Company changed its method of accounting for and presenting variable interest entities. As discussed in *Note 13* to the consolidated financial statements, in 2008 the Company changed its method of accounting for the measurement of fair value.

PricewaterhouseCoopers LLP
Baltimore, Maryland
March 1, 2011

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CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2010	2009	2008
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$ 10,883.0**	$ 12,024.3	$ 16,057.6
Regulated electric revenues	**2,752.1**	2,820.7	2,679.5
Regulated gas revenues	**704.9**	753.8	1,004.8
Total revenues	**14,340.0**	15,598.8	19,741.9
Expenses			
Fuel and purchased energy expenses	**10,001.7**	11,013.1	15,521.3
Fuel and purchased energy expenses from affiliate	**900.8**	122.5	
Operating expenses	**1,691.1**	2,228.0	2,378.8
Merger termination and strategic alternatives costs		145.8	1,204.4
Impairment losses and other costs	**2,476.8**	124.7	741.8
Workforce reduction costs		12.6	22.2
Depreciation, depletion, and amortization	**517.6**	589.1	583.2
Accretion of asset retirement obligations	**1.9**	62.3	68.4
Taxes other than income taxes	**263.9**	290.4	301.8
Total expenses	**15,853.8**	14,588.5	20,821.9
Equity Investment Earnings (Losses)	**25.0**	(6.1)	76.4
Gain on Sale of Interest in CENG		7,445.6	
Net Gain (Loss) on Divestitures	**245.8**	(468.8)	25.5
(Loss) Income from Operations	**(1,243.0)**	7,981.0	(978.1)
Other Expenses	**(76.7)**	(140.7)	(69.5)
Fixed Charges			
Interest expense	**310.8**	437.2	399.1
Interest capitalized and allowance for borrowed funds used during construction	**(33.0)**	(87.1)	(50.0)
Total fixed charges	**277.8**	350.1	349.1
(Loss) Income from Continuing Operations Before Income Taxes	**(1,597.5)**	7,490.2	(1,396.7)
Income Tax (Benefit) Expense	**(665.7)**	2,986.8	(78.3)
Net (Loss) Income	**(931.8)**	4,503.4	(1,318.4)
Net Income (Loss) Attributable to Noncontrolling Interests and BGE Preference Stock Dividends	**50.8**	60.0	(4.0)
Net (Loss) Income Attributable to Common Stock	**$ (982.6)**	$ 4,443.4	$ (1,314.4)
Average Shares of Common Stock Outstanding Basic	**200.5**	199.3	179.1
Average Shares of Common Stock Outstanding Diluted	**200.5**	200.3	179.1
(Loss) Earnings Per Common Share Basic	**$ (4.90)**	$ 22.29	$ (7.34)
(Loss) Earnings Per Common Share Diluted	**$ (4.90)**	$ 22.19	$ (7.34)

Dividends Declared Per Common Share	**$ 0.96**	$ 0.96	$ 1.91

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

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2010**	**2009**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 2,028.5**	$ 3,440.0
Accounts receivable (net of allowance for uncollectibles of **$85.0** and $80.4, respectively)	**2,059.2**	1,778.2
Accounts receivable consolidated variable interest entities (net of allowance for uncollectibles of **$87.9** and $80.2, respectively)	**308.9**	359.4
Income taxes receivable	**152.7**	
Fuel stocks	**361.1**	314.9
Materials and supplies	**104.3**	93.3
Derivative assets	**534.4**	639.1
Unamortized energy contract assets (includes **$400.9** and $371.3, respectively, related to CENG)	**544.7**	436.5
Restricted cash	**52.0**	2.7
Restricted cash consolidated variable interest entities	**52.3**	24.3
Deferred income taxes		127.9
Other	**254.5**	244.4
Total current assets	**6,452.6**	7,460.7
Investments and Other Noncurrent Assets		
Investment in CENG	**2,991.1**	5,222.9
Other investments	**189.9**	424.3
Regulatory assets (net)	**374.1**	414.4
Goodwill	**77.0**	25.5
Derivative assets	**258.9**	633.9
Unamortized energy contract assets (includes **$** and $400.9, respectively, related to CENG)	**109.8**	604.7
Other	**286.3**	304.2
Total investments and other noncurrent assets	**4,287.1**	7,629.9
Property, Plant and Equipment		
Nonregulated property, plant and equipment	**6,387.2**	5,784.6
Regulated property, plant and equipment	**7,201.7**	6,749.9
Accumulated depreciation	**(4,310.1)**	(4,080.7)
Net property, plant and equipment	**9,278.8**	8,453.8
Total Assets	**$ 20,018.5**	$ 23,544.4

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

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CONSOLIDATED BALANCE SHEETS

Constellation Energy Group, Inc. and Subsidiaries

At December 31,	**2010**	**2009**
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	**$ 32.4**	$ 46.0
Current portion of long-term debt	**245.6**	0.4
Current portion of long-term debt consolidated variable interest entities	**59.7**	56.5
Accounts payable	**1,072.6**	916.3
Accounts payable consolidated variable interest entities	**189.8**	234.2
Customer deposits and collateral	**87.2**	103.3
Derivative liabilities	**622.3**	632.6
Unamortized energy contract liabilities	**130.5**	390.1
Deferred income taxes	**56.5**	
Accrued taxes	**71.0**	877.3
Accrued expenses	**358.1**	409.8
Other	**351.5**	374.2
Total current liabilities	**3,277.2**	4,040.7
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	**2,489.8**	3,205.5
Asset retirement obligations	**32.3**	29.3
Derivative liabilities	**353.0**	674.1
Unamortized energy contract liabilities	**411.1**	653.7
Defined benefit obligations	**574.7**	743.9
Deferred investment tax credits	**27.6**	32.0
Other	**296.0**	388.8
Total deferred credits and other noncurrent liabilities	**4,184.5**	5,727.3
Long-term Debt, Net of Current Portion	**4,054.2**	4,359.6
Long-term Debt, Net of Current Portion consolidated variable interest entities	**394.6**	454.4
Equity		
Common shareholders' equity	**7,829.2**	8,697.1
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interests	**88.8**	75.3
Total equity	**8,108.0**	8,962.4
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 20,018.5**	$ 23,544.4

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Constellation Energy Group, Inc. and Subsidiaries

Year Ended December 31,	2010	2009	2008
		(In millions)	
Cash Flows From Operating Activities			
Net (loss) income	**$ (931.8)**	$ 4,503.4	$ (1,318.4)
Adjustments to reconcile to net cash provided by (used in) operating activities			
Depreciation, depletion, and amortization	**517.6**	589.1	583.2
Amortization of nuclear fuel		117.9	123.9
Amortization of energy contracts and derivatives designated as hedges	**319.6**	(138.4)	(256.3)
All other amortization	**33.3**	135.7	40.5
Accretion of asset retirement obligations	**1.9**	62.3	68.4
Deferred income taxes	**(716.4)**	1,846.9	(122.8)
Investment tax credit adjustments	**(4.5)**	(12.1)	(6.4)
Deferred fuel costs	**67.4**	68.9	52.0
Defined benefit obligation expense	**99.5**	85.3	99.6
Defined benefit obligation payments	**(324.0)**	(372.5)	(120.4)
Merger termination and strategic alternatives costs		128.2	541.8
Workforce reduction costs		12.6	22.2
Impairment losses and other costs	**2,476.8**	124.7	741.8
Impairment losses on nuclear decommissioning trust assets		62.6	165.0
Gain on sale of 49.99% membership interest in CENG		(7,445.6)	
(Gain) loss on divestitures	**(245.8)**	468.8	(38.1)
Gains on termination of contracts	**(76.8)**		(73.1)
Accrual of BGE residential customer credit		112.4	
Equity in earnings of affiliates less than dividends received	**14.1**	15.5	6.3
Derivative contracts classified as financing activities	**186.0**	1,138.3	(107.2)
Changes in working capital			
Accounts receivable, excluding margin	**(236.5)**	543.3	606.7
Derivative assets and liabilities, excluding collateral	**449.9**	425.3	(757.9)
Net collateral and margin	**44.2**	1,522.8	(960.3)
Materials, supplies, and fuel stocks	**0.1**	220.6	(33.5)
Other current assets	**(150.0)**	217.2	(95.4)
Accounts payable and accrued liabilities	**80.0**	(1,105.0)	(225.8)
Liability for unrecognized tax benefits	**(66.6)**	102.1	79.7
Accrued taxes and other current liabilities	**(1,028.4)**	788.8	(238.1)
Other	**1.7**	171.7	(38.5)
Net cash provided by (used in) operating activities	**511.3**	4,390.8	(1,261.1)
Cash Flows From Investing Activities			
Investments in property, plant and equipment	**(995.6)**	(1,529.7)	(1,934.1)
Asset acquisitions and business combinations, net of cash acquired	**(445.8)**	(41.1)	(315.3)
Investments in nuclear decommissioning trust fund securities		(385.2)	(440.6)
Proceeds from nuclear decommissioning trust fund securities		366.5	421.9
Investments in joint ventures		(201.6)	
Proceeds from sale of 49.99% membership interest in CENG		3,528.7	
Proceeds from sales of investments and other assets	**244.0**	88.3	446.3
Proceeds from investment tax credits and grants related to renewable energy investments	**56.5**		
Contract and portfolio acquisitions	**(208.3)**	(2,153.7)	
(Increase) decrease in restricted funds	**(60.3)**	1,003.3	(942.8)
Other	**(35.7)**	0.1	21.7

Net cash (used in) provided by investing activities	**(1,445.2)**	675.6	(2,742.9)
Cash Flows From Financing Activities			
Net (maturity) issuance of short-term borrowings	**(13.6)**	(809.7)	813.7
Proceeds from issuance of common stock	**14.0**	33.9	17.6
Proceeds from issuance of long-term debt	**550.0**	136.1	3,211.4
Common stock dividends paid	**(183.3)**	(228.0)	(336.3)
Reacquisition of common stock			(16.2)
BGE preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Proceeds from contract and portfolio acquisitions	**52.2**	2,263.1	
Repayment of long-term debt	**(664.5)**	(1,986.8)	(577.4)
Derivative contracts classified as financing activities	**(186.0)**	(1,138.3)	107.2
Debt and credit facility costs	**(32.8)**	(98.4)	(104.8)
Other	**(0.4)**	12.7	8.3
Net cash (used in) provided by financing activities	**(477.6)**	(1,828.6)	3,110.3
Net (Decrease) Increase in Cash and Cash Equivalents	**(1,411.5)**	3,237.8	(893.7)
Cash and Cash Equivalents at Beginning of Year	**3,440.0**	202.2	1,095.9
Cash and Cash Equivalents at End of Year	**$ 2,028.5**	$ 3,440.0	$ 202.2
Other Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 289.5**	$ 369.5	$ 341.4
Income taxes	**$ 1,044.2**	$ 57.1	$ 119.2

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENISVE INCOME (LOSS)

Constellation Energy Group, Inc. and Subsidiaries

Years Ended December 31, 2010, 2009, and 2008	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2007	178,437	$ 2,513.3	$ 3,919.5	$ (1,092.6)	$ 209.2	$ 5,549.4
Increase in noncontrolling interests from consolidation of a VIE					18.1	18.1
Comprehensive Loss						
Net loss			(1,314.4)		(4.0)	(1,318.4)
Other comprehensive loss						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(120.2)				200.6		200.6
Net unrealized loss on hedging instruments, net of taxes of $561.6				(875.3)		(875.3)
Available-for-sale securities:						
Reclassification of net losses on securities from OCI to net income, net of taxes of $(79.1)				81.7		81.7
Net unrealized losses on securities, net of taxes of $189.8				(197.5)		(197.5)
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $4.9				(7.2)		(7.2)
Net loss arising during period, net of taxes of $229.2				(339.9)		(339.9)
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(14.9)				21.3		21.3
Net unrealized loss on foreign currency translation, net of taxes of $0.1				(3.1)		(3.1)
Other				0.2		0.2
Total Comprehensive Loss			(1,314.4)	(1,119.2)	(4.0)	(2,437.6)
Effect of adoption of fair value measurement accounting standard			0.9			0.9
BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($1.91 per share)			(341.3)			(341.3)
Common stock issued and share-based awards *	21,406	667.3	(35.8)			631.5
Common stock purchased	(200)	(16.1)				(16.1)
Common stock purchased and retired	(514)					
Other			(0.2)			(0.2)
Balance at December 31, 2008	199,129	3,164.5	2,228.7	(2,211.8)	210.1	3,391.5
Contribution from noncontrolling interest					8.0	8.0
Other noncontrolling interest activity					0.4	0.4
Comprehensive Income						
Net income			4,443.4		60.0	4,503.4
Other comprehensive income						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(898.5)				1,499.4		1,499.4
Net unrealized loss on hedging instruments, net of taxes of $251.2				(474.7)		(474.7)
Available-for-sale securities:						
Reclassification of net losses on securities from OCI to net income, net of taxes of $(24.6)				25.4		25.4
Net unrealized gains on securities, net of taxes of $(78.2)				77.7		77.7
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $1.0				(1.5)		(1.5)
Net gains arising during period, net of taxes of $(23.9)				26.9		26.9
				30.3		30.3

Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(19.8)						
Deconsolidation of CENG joint venture:						
Net unrealized gains on nuclear decommissioning trust funds, net of taxes of $125.3				(125.3)		(125.3)
Net unrealized losses on defined benefit plans, net of taxes of $(94.6)				138.0		138.0
Net unrealized gains on foreign currency translation, net of taxes of $(2.7)				7.1		7.1
Other comprehensive income equity investment in CENG, net of taxes of $(11.7)				12.9		12.9
Other comprehensive income related to other equity method investees, net of taxes of $(1.3)				2.1		2.1
Total Comprehensive Income			4,443.4	1,218.3	60.0	5,721.7
BGE preference stock dividends					(13.2)	(13.2)
Common stock dividend declared ($0.96 per share)			(192.2)			(192.2)
Common stock issued and share-based awards	1,856	65.1	(18.9)			46.2
Balance at December 31, 2009	200,985	3,229.6	6,461.0	(993.5)	265.3	8,962.4

*

Includes 19.9 million shares issued to MidAmerican Energy Holdings Company.

See Notes to Consolidated Financial Statements.

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Years Ended December 31, 2010, 2009, and 2008	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Amount
	(Dollar amounts in millions, number of shares in thousands)					
Balance at December 31, 2009	200,985	$ 3,229.6	$ 6,461.0	$ (993.5)	$ 265.3	$ 8,962.4
Sale of noncontrolling interest					**(17.6)**	**(17.6)**
Distribution from noncontrolling interest					**(6.3)**	**(6.3)**
Other noncontrolling interest activity					**(0.2)**	**(0.2)**
Comprehensive Income (Loss)						
Net (loss) income			**(982.6)**		**50.8**	**(931.8)**
Other comprehensive income (loss)						
Hedging instruments:						
Reclassification of net losses on hedging instruments from OCI to net income, net of taxes of $(347.5)				**582.4**		**582.4**
Net unrealized loss on hedging instruments, net of taxes of $134.6				**(233.2)**		**(233.2)**
Available-for-sale securities:						
Reclassification of net gains on securities from OCI to net income, net of taxes of $0.1				**(0.1)**		**(0.1)**
Net unrealized gains on securities, net of taxes of $(0.1)				**0.1**		**0.1**
Defined benefit plans:						
Prior service cost arising during period, net of taxes of $(1.1)				**1.6**		**1.6**
Transition obligation arising during the period, net of taxes of $(0.2)				**0.4**		**0.4**
Net losses arising during period, net of taxes of $31.3				**(56.6)**		**(56.6)**
Amortization of net actuarial loss, prior service cost, and transition obligation included in net periodic benefit cost, net of taxes of $(15.5)				**22.7**		**22.7**
Net unrealized losses on foreign currency translation, net of taxes of $2.2				**(6.2)**		**(6.2)**
Other comprehensive income equity investment in CENG, net of taxes of $(14.1)				**9.6**		**9.6**
Other comprehensive loss related to other equity method investees, net of taxes of $0.3				**(0.5)**		**(0.5)**
Total Comprehensive Income (Loss)			**(982.6)**	**320.2**	**50.8**	**(611.6)**
BGE preference stock dividends					**(13.2)**	**(13.2)**
Common stock dividend declared ($0.96 per share)			**(193.8)**			**(193.8)**
Common stock issued and share-based awards	**1,304**	**77.4**	**(13.8)**			**63.6**
Common stock returned in connection with comprehensive agreement with EDF	**(2,500)**	**(75.3)**				**(75.3)**
Balance at December 31, 2010	**199,789**	**$ 3,231.7**	**$ 5,270.8**	**$ (673.3)**	**$ 278.8**	**$ 8,108.0**

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF INCOME

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	**2010**	**2009**	**2008**
		(In millions)	
Revenues			
Electric revenues	**$ 2,752.3**	$ 2,820.7	$ 2,679.7
Gas revenues	**709.4**	758.3	1,024.0
Total revenues	**3,461.7**	3,579.0	3,703.7
Expenses			
Operating expenses			
Electricity purchased for resale	**1,252.9**	1,217.4	1,078.1
Electricity purchased for resale from affiliate	**428.0**	623.5	802.0
Gas purchased for resale	**387.5**	449.9	694.5
Operations and maintenance	**484.5**	433.7	428.2
Operations and maintenance from affiliate	**121.6**	126.2	109.6
Impairment losses and other costs		20.0	
Workforce reduction costs			6.4
Depreciation and amortization	**249.2**	262.1	227.9
Taxes other than income taxes	**183.8**	177.8	174.5
Total expenses	**3,107.5**	3,310.6	3,521.2
Income from Operations	**354.2**	268.4	182.5
Other Income	**20.8**	25.4	29.6
Fixed Charges			
Interest expense	**135.8**	143.6	144.2
Allowance for borrowed funds used during construction	**(5.5)**	(4.3)	(4.3)
Total fixed charges	**130.3**	139.3	139.9
Income Before Income Taxes	**244.7**	154.5	72.2
Income Taxes			
Current	**(202.0)**	(119.8)	(18.2)
Deferred	**300.2**	184.7	40.2
Investment tax credit adjustments	**(1.1)**	(1.1)	(1.3)
Total income taxes	**97.1**	63.8	20.7
Net Income	**147.6**	90.7	51.5
Preference Stock Dividends	**13.2**	13.2	13.2
Net Income Attributable to Common Stock before Noncontrolling Interests	**134.4**	77.5	38.3
Net Loss Attributable to Noncontrolling Interests		7.3	
Net Income Attributable to Common Stock	**$ 134.4**	$ 84.8	$ 38.3

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	**2010**	**2009**
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 50.0**	$ 13.6
Accounts receivable (net of allowance for uncollectibles of **$34.9** and $46.2, respectively)	**351.4**	311.7
Accounts receivable, unbilled (net of allowance for uncollectibles of **$1.0** and $1.0, respectively)	**268.8**	252.7
Investment in cash pool, affiliated company		314.7
Accounts receivable, affiliated companies	**1.1**	15.4
Income taxes receivable, net	**55.9**	
Fuel stocks	**66.5**	73.8
Materials and supplies	**31.2**	31.9
Prepaid taxes other than income taxes	**51.7**	49.5
Regulatory assets (net)	**78.7**	72.5
Restricted cash consolidated variable interest entity	**29.5**	24.3
Deferred income taxes		11.2
Other	**9.5**	11.3
Total current assets	**994.3**	1,182.6
Investments and Other Assets		
Regulatory assets (net)	**374.1**	414.4
Receivable, affiliated company	**494.3**	326.2
Other	**52.2**	98.2
Total investments and other assets	**920.6**	838.8
Utility Plant		
Plant in service		
Electric	**5,127.9**	4,772.4
Gas	**1,323.0**	1,260.6
Common	**507.8**	499.0
Total plant in service	**6,958.7**	6,532.0
Accumulated depreciation	**(2,449.3)**	(2,318.2)
Net plant in service	**4,509.4**	4,213.8
Construction work in progress	**232.9**	215.5

Plant held for future use	**10.1**	2.4
Net utility plant	**4,752.4**	4,431.7
Total Assets	**$ 6,667.3**	$ 6,453.1

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

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CONSOLIDATED BALANCE SHEETS

Baltimore Gas and Electric Company and Subsidiaries

At December 31,	2010	2009
	(In millions)	
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$	$ 46.0
Current portion of long-term debt	**22.0**	
Current portion of long-term debt consolidated variable interest entity	**59.7**	56.5
Accounts payable	**252.9**	166.0
Accounts payable, affiliated companies	**84.9**	98.3
Customer deposits	**78.9**	76.0
Deferred income taxes	**30.1**	
Accrued taxes	**19.0**	80.2
Residential customer rate credit		112.4
Liability for uncertain tax positions	**62.8**	
Accrued expenses and other	**99.7**	96.1
Total current liabilities	**710.0**	731.5
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,354.9**	1,087.6
Payable, affiliated company	**250.8**	243.4
Deferred investment tax credits	**8.4**	9.5
Liability for uncertain tax positions		73.3
Other	**20.1**	20.0
Total deferred credits and other liabilities	**1,634.2**	1,433.8
Long-term Debt		
Rate stabilization bonds consolidated variable interest entity	**454.4**	510.9
Other long-term debt	**1,431.5**	1,431.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Unamortized discount and premium	**(2.0)**	(2.2)
Current portion of long-term debt	**(22.0)**	
Current portion of long-term debt consolidated variable interest entity	**(59.7)**	(56.5)
Total long-term debt	**2,059.9**	2,141.4
Equity		
Common shareholder's equity	**2,073.2**	1,938.8
Preference stock not subject to mandatory redemption	**190.0**	190.0
Noncontrolling interest		17.6
Total equity	**2,263.2**	2,146.4
Commitments, Guarantees, and Contingencies (see Note 12)		
Total Liabilities and Equity	**$ 6,667.3**	$ 6,453.1

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Baltimore Gas and Electric Company and Subsidiaries

Year Ended December 31,	2010	2009	2008
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 147.6**	$ 90.7	$ 51.5
Adjustments to reconcile to net cash provided by operating activities			
Depreciation and amortization	**249.2**	262.1	227.9
Other amortization	**5.2**	9.2	13.2
Deferred income taxes	**300.2**	184.7	40.2
Investment tax credit adjustments	**(1.1)**	(1.1)	(1.3)
Deferred fuel costs	**67.4**	68.9	52.0
Defined benefit plan expenses	**36.0**	32.7	30.6
Allowance for equity funds used during construction	**(10.5)**	(8.2)	(8.0)
Accrual of residential customer rate credit		112.4	
Impairment losses and other costs		20.0	
Workforce reduction costs			6.4
Changes in:			
Accounts receivable	**(57.6)**	(5.1)	(33.1)
Accounts receivable, affiliated companies	**14.3**	(11.1)	(0.1)
Materials, supplies, and fuel stocks	**8.0**	76.4	(40.6)
Income taxes receivable, net	**(55.9)**		
Other current assets	**(6.6)**	(10.2)	(4.5)
Accounts payable	**87.5**	(65.0)	48.6
Accounts payable, affiliated companies	**(13.4)**	1.3	(67.5)
Other current liabilities	**(121.5)**	62.7	(11.4)
Long-term receivables and payables, affiliated companies	**(200.8)**	(197.8)	(45.7)
Regulatory assets, net	**(64.3)**	(44.4)	(18.7)
Other	**(64.9)**	67.6	(10.4)
Net cash provided by operating activities	**318.8**	645.8	229.1
Cash Flows From Investing Activities			
Utility construction expenditures (excluding equity portion of allowance for funds used during construction)	**(496.8)**	(372.6)	(426.4)
Change in cash pool at parent	**314.7**	(165.9)	(70.4)
Proceeds from sales of investments and other assets	**20.9**		12.9
(Increase) decrease in restricted funds	**(5.2)**	(0.6)	15.5
Net cash used in investing activities	**(166.4)**	(539.1)	(468.4)
Cash Flows From Financing Activities			
Net (repayment) issuance of short-term borrowings	**(46.0)**	(324.0)	370.0
Proceeds from issuance of long-term debt			400.0
Repayment of long-term debt	**(56.5)**	(90.0)	(350.0)
Debt issuance costs	**(0.3)**	(0.5)	(2.7)
Contribution from noncontrolling interest		8.0	
Preference stock dividends paid	**(13.2)**	(13.2)	(13.2)
Contribution from (distribution to) parent		315.9	(171.7)

Net cash (used in) provided by financing activities		**(116.0)**		(103.8)		232.4
Net Increase (Decrease) in Cash and Cash Equivalents		**36.4**		2.9		(6.9)
Cash and Cash Equivalents at Beginning of Year		**13.6**		10.7		17.6
Cash and Cash Equivalents at End of Year	**$**	**50.0**	$	13.6	$	10.7
Other Cash Flow Information:						
Cash paid (received) during the year for:						
Interest (net of amounts capitalized)	**$**	**127.9**	$	136.9	$	126.6
Income taxes	**$**	**(76.0)**	$	(250.9)	$	(5.1)

See Notes to Consolidated Financial Statements

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

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Notes to Consolidated Financial Statements

1 Significant Accounting Policies

Nature of Our Business

Constellation Energy Group, Inc. (Constellation Energy) is an energy company that conducts its business through various subsidiaries organized around three business segments: a generation business (Generation), a customer supply business (NewEnergy), and Baltimore Gas and Electric Company (BGE). Our Generation and NewEnergy businesses are competitive providers of energy solutions for a variety of customers. BGE is a regulated electric transmission and distribution utility company and a regulated gas distribution utility company with a service territory that covers the City of Baltimore and all or part of ten counties in central Maryland. We describe our operating segments in *Note 3*.

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

Consolidation Policy

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

Consolidation

We use consolidation for two types of entities:

- subsidiaries in which we own a majority of the voting stock and exercise control over the operations and policies of the company, and
- variable interest entities (VIEs) for which we are the primary beneficiary, which means that we have a controlling financial interest in a VIE. We discuss our investments in VIEs in more detail in *Note 4*.

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

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies where we hold a significant influence, which generally approximates a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income (Loss). If our carrying value of the investment differs from our share of the investee's equity, we recognize this basis difference as an adjustment of our share of the investee's earnings.

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

The Cost Method

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

Sale of Subsidiary Ownership Interests

We may sell portions of our ownership interests in a subsidiary's stock. Through 2008, we recorded gains or losses on such sales in our Consolidated Statements of Income (Loss), as a component of non-operating income. Beginning in 2009, we treat sales of subsidiary stock as an equity transaction and do not recognize any gains or losses on the transaction as long as we retain a controlling financial interest.

When we sell ownership interests in our subsidiaries and do not retain a controlling financial interest, we deconsolidate that subsidiary. Upon deconsolidation, we recognize a gain or loss for the difference between the sum of the fair value of any consideration received and the fair value of our retained investment and the carrying amount of the former subsidiary's assets and liabilities.

On November 6, 2009, we completed the sale of a 49.99% membership interest in Constellation Energy Nuclear Group LLC and affiliates (CENG), our nuclear generation and operation business, to EDF Group and affiliates (EDF). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG at that time. We account for our retained interest in CENG using the equity method. See *Note 2* for the gain recognized in 2009 on our sale of a 49.99% interest in CENG to EDF.

Regulation of Electric and Gas Business

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

When this happens, we and BGE must defer (include as an asset or liability in the Consolidated Balance Sheets and exclude from Consolidated Statements of Income (Loss)) certain

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regulated business expenses and income as regulatory assets and liabilities. We and BGE have recorded these regulatory assets and liabilities in the Consolidated Balance Sheets.

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

Use of Accounting Estimates

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

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

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

Reclassifications

In accordance with the presentation requirements for consolidated VIEs, which we adopted on January 1, 2010, we have separately presented the following material assets and liabilities of these VIEs on our, and/or BGE's, Consolidated Balance Sheets:

- "Accounts receivable consolidated variable interest entities,"
- "Restricted cash consolidated variable interest entities,"
- "Current portion of long-term debt consolidated variable interest entities,"
- "Accounts payable consolidated variable interest entities," and
- "Long-term Debt, Net of Current Portion consolidated variable interest entities."

We discuss our adoption of the reporting requirements for consolidated variable interest entities later in this Note.

We have also reclassified certain prior-period amounts:

- We have separately presented "Fuel and purchased energy expenses from affiliate" that was previously reported within "Fuel and purchased energy expenses" on our Consolidated Statements of Income (Loss).
- We have separately presented "Accounts Payable" that was previously reported within "Accounts Payable and Accrued Liabilities" on our Consolidated Balance Sheets.
- We have separately presented "Regulatory assets, net" that was previously reported within "Other" on BGE's Consolidated Statements of Cash Flows.

Revenues

Sources of Revenue

We earn revenues from the following primary business activities:

sale of energy and energy-related products, including electricity, natural gas, and other commodities, in nonregulated markets;

sale and delivery of electricity and natural gas to customers of BGE;

trading energy and energy-related commodities; and,

providing other energy-related nonregulated products and services.

We report BGE's revenues from the sale and delivery of electricity and natural gas to its customers as "Regulated electric revenues" and "Regulated gas revenues" in our Consolidated Statements of Income (Loss). We report all other revenues as "Nonregulated revenues."

Revenues from nonregulated activities result from contracts or other sales that generally reflect market prices in effect at the time that we executed the contract or the sale occurred. BGE's revenues from regulated activities reflect provisions of orders of the Maryland PSC and the FERC. In certain cases, these orders require BGE to defer the difference between certain portions of its actual costs and the amount presently billable to customers. BGE records these differences as regulatory assets or liabilities, which we discuss in more detail in *Note 6*. We describe the effects of these orders on BGE's revenues below.

Regulated Electric

BGE provides market-based standard offer electric service to its residential, commercial, and industrial customers. BGE charges these customers standard offer service (SOS) rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component. Pursuant to Senate Bill 1, the energy legislation enacted in Maryland in June 2006, BGE suspended collection of the shareholder return component of the administrative fee for residential SOS service beginning January 1, 2007 for a 10-year period. However, under an order issued by the Maryland PSC in May 2007, as of June 1, 2007, BGE reinstated collection of the residential return component of the SOS administration charge and began providing all residential electric customers a credit for the return component of the administrative charge. As part of the 2008 Maryland settlement agreement, which is discussed in more detail in *Note 2*, BGE resumed collection of the shareholder return portion of the residential standard offer service administrative charge from June 1, 2008 through May 31, 2010 without having to rebate it to all residential electric customers. Starting June 1, 2010, BGE is providing all residential electric customers a credit for the residential return component of the administrative charge, which will continue through December 2016.

As part of the October 30, 2009 order from the Maryland PSC approving our transaction with EDF, BGE was permitted to file an electric distribution rate case at any time beginning in January 2010 and could not file a subsequent electric

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distribution rate case until January 2011. Any rate increase in the first electric distribution rate case was capped at 5%.

In May 2010, BGE filed an electric and gas distribution rate case with the Maryland PSC and the Maryland PSC issued an abbreviated order in December 2010. The order authorizes BGE to increase electric distribution rates by $31.0 million and was based on an 8.06% rate of return with a 9.86% return on equity and a 52% equity ratio.

BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge portion of SOS rates in a given period. BGE either bills or refunds its customers the difference in the future.

Regulated Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses." Under these clauses, BGE defers the difference between certain of its actual costs related to the gas commodity and what it collects from customers under the commodity charge in a given period for evaluation under a market-based rates incentive mechanism. For each period subject to that mechanism, BGE compares its actual cost of gas to a market index (a measure of the market price of gas for that period) and shares the difference equally between shareholders and customers through an adjustment to the price of gas service in future periods. This sharing mechanism excludes fixed-price contracts which the Maryland PSC requires BGE to procure for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period. As a condition to the October 30, 2009 order from the Maryland PSC approving our transaction with EDF, BGE was permitted to file a gas distribution case at any time beginning in January 2010 and could not file a subsequent gas distribution rate case until January 2011.

In May 2010, BGE filed an electric and gas distribution rate case with the Maryland PSC and the Maryland PSC issued an abbreviated order in December 2010. The order authorizes BGE to increase gas distribution rates by $9.8 million and was based on a 7.90% rate of return with a 9.56% return on equity and a 52% equity ratio.

Selection of Accounting Treatment

We determine the appropriate accounting treatment for recognizing revenues based on the nature of the transaction, governing accounting standards and, where required, by applying judgment as to the most transparent presentation of the economics of the underlying transactions. We utilize two primary accounting treatments to recognize and report revenues in our results of operations:

- accrual accounting, including hedge accounting, and
- mark-to-market accounting.

We describe each of these accounting treatments below.

Accrual Accounting

Under accrual accounting, we record revenues in the period when we deliver energy commodities or products, render services, or settle contracts. We generally use accrual accounting to recognize revenues for our sales of electricity, gas, coal, and other commodities as part of our physical delivery activities. We enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to BGE's customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators. We discuss the NPNS election later in this Note under *Derivatives and Hedging Activities*.

However, we also use mark-to-market accounting rather than accrual accounting for recognizing revenue on our competitive retail gas customer supply activities, our fixed quantity competitive retail power customer supply activities for new transactions closed after June 30, 2010, which are managed using economic hedges that we have not designated as cash-flow hedges so as to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and other physical commodity derivatives if we have not designated those contracts as NPNS.

We record accrual revenues from sales of products or services on a gross basis at the contract, tariff, or spot price because we are a principal to the transaction. Accrual revenues also include certain other gains and losses that relate to these activities or for which accrual accounting is required.

We include in accrual revenues the effects of hedge accounting for derivative contracts that qualify as hedges of our sales of products or services. Substantially all of the derivatives that we designate as hedges are cash flow hedges. We recognize the effective portion of hedge gains or losses in revenues during the same period in which we record the revenues from the hedged transaction. We record any hedge ineffectiveness in revenues when it occurs. We discuss our hedge accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

We may make or receive cash payments at the time we assume previously existing power sale agreements for which the contract price differs from current market prices. We also may designate a derivative as NPNS after its inception. We recognize the value of these derivatives in our Consolidated Balance Sheets as an "Unamortized energy contract" asset or liability. We amortize these assets and liabilities into revenues based on the present value of the underlying cash flows provided by the contracts.

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The following table summarizes the primary components of accrual revenues:

Component of Accrual Revenues	Nonregulated Physical Energy Delivery	Activity Regulated Electricity and Gas Sales	Other Nonregulated Products and Services
Gross amounts receivable for sales of products or services based on contract, tariff, or spot price	X	X	X
Reclassification of net gains/losses on cash flow hedges from AOCI	X		
Ineffective portion of net gains/losses on cash flow hedges	X		
Amortization of acquired energy contract assets or liabilities	X		
Recovery or refund of deferred SOS and gas cost adjustment clause regulatory assets/liabilities		X	

Mark-to-Market Accounting

We record revenues using the mark-to-market method of accounting for transactions under derivative contracts for which we are not permitted, or do not elect, to use accrual accounting or hedge accounting. These mark-to-market transactions primarily relate to our risk management and trading activities, our competitive retail gas customer supply activities, and economic hedges of other accrual activities. Mark-to-market revenues include:

- origination gains or losses on new transactions,
- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

Under the mark-to-market method of accounting, we record any inception fair value of these contracts as derivative assets and liabilities at the time of contract execution. We record subsequent changes in the fair value of these derivative assets and liabilities on a net basis in "Nonregulated revenues" in our Consolidated Statements of Income (Loss). We discuss our mark-to-market accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

Fuel and Purchased Energy Expenses

Sources of Fuel and Purchased Energy Expenses

We incur fuel and purchased energy costs for:

- the fuel we use to generate electricity at our power plants,
- purchases of electricity from others, and
- purchases of natural gas, coal, and other fuel types that we resell.

We report these costs in "Fuel and purchased energy expenses" in our Consolidated Statements of Income (Loss). We also include certain fuel-related direct costs, such as ancillary services purchased from independent system operators, transmission costs, brokerage fees, and freight costs in the same category in our Consolidated Statements of Income (Loss).

Fuel and purchased energy costs from nonregulated activities result from contracts or other purchases that generally reflect market prices in effect at the time that we executed the contract or the purchase occurred. BGE's costs of electricity and gas for resale under regulated activities reflect actual costs of purchases, adjusted to reflect provisions of orders of the Maryland PSC and the FERC. In certain cases, these orders require BGE to defer the difference between certain portions of its actual costs and the amount presently billable to customers. BGE records these differences as regulatory assets or liabilities, which we discuss in more detail in *Note 6*. We describe the effects of these orders on BGE's fuel and purchased energy expense below.

Regulated Electric

BGE provides market-based standard offer electric service to its residential, commercial, and industrial customers. BGE charges these customers SOS rates that are designed to recover BGE's wholesale power supply costs and include an administrative fee consisting of a shareholder return component and an incremental cost component. Starting June 1, 2010, BGE is providing all residential electric customers a credit for the residential return component of the administrative charge, which will continue through December 2016.

BGE defers the difference between certain of its actual costs related to the electric commodity and what it collects from customers under the commodity charge portion of SOS rates in a given period. BGE either bills or refunds its customers the difference in the future and includes amortization of the deferred amounts in fuel and purchased energy expense. Therefore, BGE does not earn a profit on the cost of fuel and purchased energy because its expense approximates the amount of the related commodity charge included in revenues for the period, reflecting actual costs adjusted for the effects of the regulatory deferral mechanism.

Regulated Gas

BGE charges its gas customers for the natural gas they purchase from BGE using "gas cost adjustment clauses." These clauses include a market-based rates incentive mechanism that requires BGE to compare its actual cost of gas to a market index (a measure of the market price of gas for that period) and share the difference equally between shareholders and customers. This

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sharing mechanism excludes fixed-price contracts which the Maryland PSC requires BGE to procure for at least 10%, but not more than 20%, of forecasted system supply requirements for the November through March period.

BGE defers the difference between the portion of its actual gas commodity costs subject to the market-based rates incentive mechanism and what it collects from customers under the commodity charge in a given period. BGE either bills or refunds its customers the portion of this difference to which they are entitled through an adjustment to the price of gas service in future periods and includes amortization of the deferred amounts in fuel and purchased energy expense.

Selection of Accounting Treatment

We determine the appropriate accounting treatment for fuel and purchased energy costs based on the nature of the transaction, governing accounting standards and, where required, by applying judgment as to the most transparent presentation of the economics of the underlying transactions. We utilize two primary accounting treatments to recognize and report these costs in our Consolidated Statements of Income (Loss):

- accrual accounting, including hedge accounting, and
- mark-to-market accounting.

We describe each of these accounting treatments below.

Accrual Accounting

Under accrual accounting, we record fuel and purchased energy expenses in the period when we consume the fuel or purchase the electricity or other commodity for resale. We use accrual accounting to recognize substantially all of our fuel and purchased energy expenses as part of our physical delivery activities. We make these purchases using a variety of instruments, including non-derivative transactions, derivatives that qualify for and are designated as NPNS, and spot-market purchases, including settlements with independent system operators. These transactions also include power purchase agreements that qualify as operating leases, for which fuel and purchased energy consists of both fixed capacity payments and variable payments based on the actual output of the plants. We discuss the NPNS election later in this Note under *Derivatives and Hedging Activities*.

In certain cases, we use mark-to-market accounting rather than accrual accounting for recognizing fuel and purchased energy expenses on physical commodity derivatives if we have not designated those contracts as NPNS.

We include in accrual fuel and purchased energy expenses the effects of hedge accounting for derivative contracts that qualify as hedges of our fuel and purchased energy costs. Substantially all of the derivatives that we designate as hedges are cash flow hedges. We recognize the effective portion of hedge gains or losses in fuel and purchased energy expenses during the same period in which we record the costs from the hedged transaction. We record any hedge ineffectiveness in expense when it occurs. We discuss our use of hedge accounting in the *Derivatives and Hedging Activities* section later in this Note.

We may make or receive cash payments at the time we assume previously existing power purchase agreements or other contracts for which the contract price differs from current market prices. We recognize the cash payment at inception in our Consolidated Balance Sheets as an "Unamortized energy contract" asset or liability. We amortize these assets and liabilities into fuel and purchased energy expenses based on the present value of the underlying cash flows provided by the contracts.

The following table summarizes the primary components of accrual purchased fuel and energy expense:

Component of Accrual Fuel and Purchased Energy Expense	Nonregulated Physical Energy Delivery	Activity Regulated Electricity and Gas Sales	Other Nonregulated Products and Services
Actual costs of fuel and purchased energy	X	X	X
Reclassification of net gains/losses on cash flow hedges from AOCI	X		

Ineffective portion of net gains/losses on cash flow hedges	X	
Amortization of acquired energy contract assets or liabilities	X	
Deferral or amortization of deferred SOS and gas cost adjustment clause regulatory assets/liabilities		X

Mark-to-Market Accounting

We record fuel and purchased energy expenses using the mark-to-market method of accounting for transactions under derivative contracts for which we are not permitted, or do not elect, to use accrual accounting or hedge accounting in order to match the earnings impacts of those activities to the greatest extent permissible. These mark-to-market transactions relate to our physical international coal purchase contracts in 2009 and 2008. Mark-to-market costs include:

- unrealized gains and losses from changes in the fair value of open contracts,
- net gains and losses from realized transactions, and
- changes in valuation adjustments.

Under the mark-to-market method of accounting, we record any inception fair value of these contracts as derivative assets and liabilities at the time of contract execution. We record subsequent changes in the fair value of these derivative assets and liabilities on a net basis in "Fuel and purchased energy expense" in our Consolidated Statements of Income (Loss). We discuss our mark-to-market accounting policy in the *Derivatives and Hedging Activities* section later in this Note.

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Derivatives and Hedging Activities

We engage in electricity, natural gas, coal, emission allowances, and other commodity marketing and risk management activities as part of our NewEnergy business. In order to manage our exposure to commodity price fluctuations, we enter into energy and energy-related derivative contracts traded in the over-the-counter markets or on exchanges. These contracts include:

- forward physical purchase and sales contracts,
- futures contracts,
- financial swaps, and
- option contracts.

We use interest rate swaps to manage our interest rate exposures associated with new debt issuances, to manage our exposure to fluctuations in interest rates on variable rate debt, and to optimize the mix of fixed and floating-rate debt. We use foreign currency swaps to manage our exposure to foreign currency exchange rate fluctuations.

Selection of Accounting Treatment

We account for derivative instruments and hedging activities in accordance with several possible accounting treatments that meet all of the requirements of the accounting standard. Mark-to-market is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the other elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis.

The following are permissible accounting treatments for derivatives:

- mark-to-market,
- cash flow hedge,
- fair value hedge, and
- NPNS.

Each of the accounting treatments for derivatives affects our financial statements in substantially different ways as summarized below:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Mark-to-market	Derivative asset or liability recorded at fair value	Changes in fair value recognized in earnings
Cash flow hedge	Derivative asset or liability recorded at fair value Effective changes in fair value recognized in accumulated other comprehensive income	Ineffective changes in fair value recognized in earnings Amounts in accumulated other comprehensive income reclassified to earnings when the hedged forecasted transaction affects earnings or becomes probable of not occurring
Fair value hedge	Derivative asset or liability recorded at fair value	Changes in fair value recognized in earnings
	Book value of hedged asset or liability adjusted for changes in its fair value	Changes in fair value of hedged asset or liability recognized in earnings
NPNS (accrual)	Fair value not recorded Accounts receivable or accounts payable recorded when derivative settles	Changes in fair value not recognized in earnings Revenue or expense recognized in earnings when underlying physical commodity is sold or consumed

Mark-to-Market

We generally apply mark-to-market accounting for risk management and trading activities because changes in fair value more closely reflect the economic performance of the activity. However, we also use mark-to-market accounting for derivatives related to the following physical energy delivery activities:

- our competitive retail gas customer supply activities, which are managed using economic hedges that we have not designated as cash-flow hedges, in order to match the timing of recognition of the earnings impacts of those activities to the greatest extent permissible, and
- economic hedges of activities that require accrual accounting for which the related hedge requires mark-to-market accounting.

We may record origination gains associated with derivatives subject to mark-to-market accounting. Origination gains represent the initial fair value of certain structured transactions that our portfolio management and trading operation executes to meet the risk management needs of our customers. Historically, transactions that result in origination gains have been unique and resulted in individually significant gains from a single transaction. We generally recognize origination gains when we are able to obtain observable market data to validate that the initial fair value of the contract differs from the contract price.

Cash Flow Hedge

We generally elect cash flow hedge accounting for most of the derivatives that we use to hedge market price risk for our physical energy delivery (Generation and NewEnergy businesses) activities because cash flow hedge accounting more closely aligns the timing of earnings recognition, cash flows, and the underlying business activities. We only use fair value hedge accounting on a limited basis.

We use regression analysis to determine whether we expect a derivative to be highly effective as a cash flow hedge prior to electing hedge accounting and also to determine whether all derivatives designated as cash flow hedges have been effective. We perform these effectiveness tests prior to designation for all new hedges and on a daily basis for all existing hedges. We calculate the actual amount of ineffectiveness on our cash flow hedges using the "dollar offset" method, which compares changes in the expected cash flows of the hedged transaction to changes in the value of expected cash flows from the hedge.

We discontinue hedge accounting when our effectiveness tests indicate that a derivative is no longer highly effective as a hedge; when the derivative expires or is sold, terminated or exercised; when the hedged item matures, is sold or repaid; or when we determine that the occurrence of the hedged forecasted transaction is not probable. When we discontinue hedge accounting but continue to hold the derivative, we begin to apply mark-to-market accounting at that time.

NPNS

We elect NPNS accounting for derivative contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Once we elect NPNS classification for a given contract, we do not subsequently change the election and treat the contract as a derivative using mark-to-market or hedge accounting. However, if we were to determine that a transaction designated as NPNS no longer qualified for the NPNS election, we would have to record the fair value of that contract on the balance sheet at that time and immediately recognize that amount in earnings.

Fair Value

We record mark-to-market and hedge derivatives at fair value, which represents an exit price for the asset or liability from the perspective of a market participant. An exit price is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. While some of our derivatives relate to commodities or instruments for which quoted market prices are available from external sources, many other commodities and related contracts are not actively traded. Additionally, some contracts include quantities and other factors that vary over time. As a result, often we must use modeling techniques to estimate expected future market prices, contract quantities, or both in order to determine fair value.

The prices, quantities, and other factors we use to determine fair value reflect management's best estimates of inputs a market participant would consider. We record valuation adjustments to reflect uncertainties associated with estimates inherent in the determination of fair value that are not incorporated in market price information or other market-based estimates we use to determine fair value. 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.

The valuation adjustments we record include the following:

- Close-out adjustment 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 purchase contracts at the bid price and sale contracts at the offer price.
- Unobservable input valuation adjustment necessary when we determine fair value for derivative positions using internally developed models that use unobservable inputs due to the absence of observable market information.
- Credit spread adjustment necessary to reflect the credit-worthiness of each customer (counterparty).

We discuss derivatives and hedging activities as well as how we determine fair value in detail in *Note 13*.

Balance Sheet Netting

We often transact with counterparties under master agreements and other arrangements that provide us with a right of setoff of amounts due to us and from us in the event of bankruptcy or default by the counterparty. We report these transactions on a net basis in our Consolidated Balance Sheets.

We apply balance sheet netting separately for current and noncurrent derivatives. Current derivatives represent the portion of derivative contract cash flows expected to occur within 12 months, and noncurrent derivatives represent the portion of those cash flows expected to occur beyond 12 months. Within each of these categories, we net all amounts due to and from each counterparty under master agreements into a single net asset or liability. We include fair value cash collateral amounts received and posted in determining this net asset and liability amount.

Unamortized Energy Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balance of non-derivative energy contracts that we acquired, certain contracts which no longer qualify as derivatives due to the absence of a liquid market, or derivatives designated as NPNS that we had previously recorded as "Derivative assets or liabilities." The initial amount recorded represents the fair value of the contract at the time of acquisition or designation, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. The amortization of these values is discussed in the *Revenues* and *Fuel and Purchased Energy Expenses* sections of this Note.

Credit Risk

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

Electric and gas utilities, municipalities, cooperatives, generation owners, coal producers, and energy marketers comprise the majority of counterparties underlying our assets from our wholesale marketing and risk management activities. We held cash collateral from these counterparties totaling $28.8 million as of December 31, 2010 and $95.2 million as of December 31, 2009. These amounts are included in "Customer deposits and collateral" in our Consolidated Balance Sheets.

We consider a significant concentration of credit risk to be any single obligor or counterparty whose concentration exceeds 10% of total credit exposure. As of December 31, 2010, two

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counterparties, CENG and a large power cooperative, comprise total exposure concentrations of 25%. No counterparties based in a single country other than the United States in aggregate comprise more than 10% of the total exposure of the portfolio.

Equity Investment (Losses) Earnings

We include equity in earnings from our investments in qualifying facilities and power projects, joint ventures, and Constellation Energy Partners LLC (CEP) in "Equity Investment (Losses) Earnings" in our Consolidated Statements of Income (Loss) in the period they are earned. "Equity Investment (Losses) Earnings" also includes any adjustments to amortize the difference, if any, except for goodwill and land, between our cost in an equity method investment and our underlying equity in net assets of the investee at the date of investment.

We consider our investments in generation-related qualifying facilities, power projects, and joint ventures to be integral to our operations.

Taxes

We summarize our income taxes in *Note 10*. BGE and our other subsidiaries record their allocated share of our consolidated federal income tax liability using the percentage complementary method specified in U.S. income tax regulations. As you read this section, it may be helpful to refer to *Note 10*.

Income Tax Expense

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

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

Tax Credits

We defer the investment tax credits associated with our regulated business, assets previously held by our regulated business, and any investment tax credits that are convertible to cash grants in our Consolidated Balance Sheets. The investment tax credits that are convertible to cash grants are recorded as a reduction to the carrying value of the underlying property and subsequently amortized evenly to earnings over the life of each underlying property. We reduce current income tax expense in our Consolidated Statements of Income (Loss) for any investment tax credits that are not convertible to cash grants and other tax credits associated with our nonregulated businesses.

Deferred Income Tax Assets and Liabilities

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

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

Interest and Penalties

We recognize interest and penalties related to tax underpayments, assessments, and unrecognized tax benefits in "Income tax expense (benefit)" in our Consolidated Statements of Income (Loss).

Unrecognized Tax Benefits

We recognize in our financial statements the effects of uncertain tax positions if we believe that these positions are "more-likely-than-not" to be realized. We establish liabilities to reflect the portion of those positions we cannot conclude are "more-likely-than-not" to be realized upon ultimate settlement. These are referred to as liabilities for unrecognized tax benefits.

We discuss our unrecognized tax benefits in more detail in *Note 10*.

State and Local Taxes

State and local income taxes are included in "Income tax expense (benefit)" in our Consolidated Statements of Income (Loss).

Taxes Other Than Income Taxes

Taxes other than income taxes primarily include property and gross receipts taxes along with franchise taxes and other non-income taxes, surcharges, and fees.

BGE and our NewEnergy business collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer and others are imposed on BGE and our NewEnergy business. Where these taxes, such as sales taxes, are imposed on the customer, we account for these taxes on a net basis with no impact to our Consolidated Statements of Income (Loss). However, where these taxes, such as gross receipts taxes or other surcharges or fees, are imposed on BGE or our NewEnergy business, we account for these taxes on a gross basis. Accordingly, we recognize revenues for these taxes collected from customers along with an offsetting tax expense, which are both included in our Consolidated

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Statements of Income (Loss). The taxes, surcharges, or fees that are included in revenues were as follows:

Year Ended December 31,	2010	2009	2008
		(In millions)	
Constellation Energy (including BGE)	**$ 122.2**	$ 106.8	$ 111.7
BGE	**81.9**	76.8	73.2

Earnings Per Share

Basic earnings per common share (EPS) is computed by dividing net income (loss) attributable to common stock by the weighted-average number of common shares outstanding for the year. Diluted EPS reflects the potential dilution of common stock equivalent shares that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Our dilutive common stock equivalent shares primarily consist of stock options and other stock-based compensation awards. The following table presents stock options that were not dilutive and were excluded from the computation of diluted EPS in each period, as well as the dilutive common stock equivalent shares as follows:

Year Ended December 31,	2010	2009	2008
		(In millions)	
Non-dilutive stock options	**5.6**	5.1	2.6
Dilutive common stock equivalent shares	**1.6**	1.0	5.5

As a result of the Company incurring a loss for the years ended December 31, 2010 and December 31, 2008, diluted common stock equivalent shares were not included in calculating diluted EPS for those reporting periods.

We issued to MidAmerican Energy Holdings Company (MidAmerican) 19,897,322 shares of Constellation Energy's common stock upon the conversion of the Series A Preferred Stock, which occurred upon the termination of the merger agreement with MidAmerican on December 17, 2008. These additional shares impacted our earnings per share for 2009.

Stock-Based Compensation

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

We recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Equity-based compensation awards include stock options, restricted stock, and any other share-based payments. We recognize compensation cost over the period during which an employee is required to provide service in exchange for the award, which is typically a one to five-year period. We use a forfeiture assumption based on historical experience to estimate the number of awards that are expected to vest during the service period, and ultimately true-up the estimated expense to the actual expense associated with vested awards. We estimate the fair value of stock option awards on the date of grant using the Black-Scholes option-pricing model and we remeasure the fair value of liability awards each reporting period. We do not capitalize any portion of our stock-based compensation.

Cash and Cash Equivalents

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

Accounts Receivable and Allowance for Uncollectibles

Accounts receivable, which includes cash collateral posted in our margin account with third party brokers, are stated at the historical carrying amount net of write-offs and allowance for uncollectibles. We establish an allowance for uncollectibles based on our expected exposure to the credit risk of customers based on a variety of factors.

Materials, Supplies, and Fuel Stocks

We record our fuel stocks, emissions credits, renewable energy credits, coal held for resale, and materials and supplies at the lower of cost or market. We determine cost using the average cost method for our entire inventory.

Restricted Cash

At December 31, 2010, our restricted cash primarily included cash at one of our consolidated variable interest entities, cash held in escrow for the acquisition of the Boston Generating fleet of generating plants, and BGE's funds restricted for the repayment of the rate stabilization bonds. At December 31, 2009, restricted cash also included proceeds from financing for the acquisition, construction, installation and equipping of certain sewage and solid waste disposal facilities at our Brandon Shores coal-fired generating plant in Maryland.

As of December 31, 2010 and 2009, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for the repayment of the rate stabilization bonds. We discuss the rate stabilization bonds in more detail in *Note 9*.

Financial Investments

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

We report our debt and equity securities at fair value, and we use either specific identification or average cost to determine their cost for computing realized gains or losses.

Available-for-Sale Securities

We classify our investments in trust assets securing certain executive benefits that are classified as available-for-sale securities.

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

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

Long-Lived Assets

We 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. We test our long-lived assets and proved gas properties for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable.

We determine if long-lived assets and proved gas properties are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. Cash flows for long-lived assets are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Undiscounted expected future cash flows for proved gas properties include risk-adjusted probable and possible reserves.

We record an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. The amount of the impairment loss we record equals the difference between the estimated fair value of the asset and its carrying amount in our accounting records.

We evaluate unproved gas producing properties at least annually to determine if they are impaired. 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.

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

Investments

We evaluate our equity method and cost method investments (for example, CENG, CEP and partnerships that own power projects) to determine whether or not they are impaired. The standard for determining whether an impairment must be recorded is whether the investment has experienced an "other than a temporary" decline in value.

Additionally, if the projects in which we hold these investments recognize an impairment, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value.

We continuously monitor issues that potentially could impact future profitability of our equity method investments that own coal, hydroelectric, fuel processing projects, as well as our equity investments in our nuclear joint venture and CEP. These issues include environmental and legislative initiatives.

Debt and Equity Securities

We determine whether a decline in fair value of a debt or equity investment below book value is other than temporary. If we determine that the decline in fair value is other than temporary, we write-down the cost basis of the investment to fair value as a new cost basis.

Goodwill and Intangible Assets

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We do not amortize goodwill. We 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 our businesses using techniques similar to those used to estimate future cash flows for long-lived assets as previously discussed. If the estimated fair value of the business is less than its carrying value, an impairment loss is required to be recognized to the extent that the carrying value of goodwill is greater than its fair value. We amortize intangible assets with finite lives. We discuss the changes in our goodwill and intangible assets in more detail in *Note 5*.

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

We report our property, plant and equipment at its original cost, unless impaired.

Original cost includes:

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

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the Conemaugh substation and transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $338.0 million at December 31, 2010 and $339.6 million at December 31, 2009. Each owner is responsible for financing its proportionate share of the plants' working funds. Working funds are used for operating expenses and capital expenditures. Operating expenses related to these plants are included in "Operating expenses" in our Consolidated Statements of Income (Loss). Capital costs related to these plants are included in "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets.

The "Nonregulated property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $70.9 million at December 31, 2010 and $685.1 million at December 31, 2009.

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

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

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Our oil and gas exploration and production activities consist of working interests in gas producing fields. We account for these activities under the successful efforts method of accounting. Acquisition, development, and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

Depreciation and Depletion Expense

We compute depreciation for our generating, electric transmission and distribution, and gas distribution facilities. We compute depletion for our oil and gas exploitation and production activities. Depreciation and depletion are determined using the following methods:

- the group straight-line method using rates averaging approximately 2.9% per year for our generating assets,
- the group straight-line method, approved by the Maryland PSC, applied to the average investment, adjusted for anticipated costs of removal less salvage, in classes of depreciable property based on an average rate of approximately 3.2% per year for our regulated business, or
- the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

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

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

Amortization Expense

Amortization is an accounting process of reducing an asset amount in our Consolidated Balance Sheets over a period of time that approximates the asset's useful life. When we reduce amounts in our Consolidated Balance Sheets, we record amortization expense in our Consolidated Statements of Income (Loss). We discuss the types of assets that we amortize and the periods over which we amortize them in more detail in *Note 5*.

Accretion Expense

We recognize an estimated liability for legal obligations and legal obligations conditional upon a future event associated with the retirement of tangible long-lived assets. Our conditional asset retirement obligations relate primarily to asbestos removal at certain of our generating facilities.

Prior to November 6, 2009, substantially all of our total asset retirement obligation was associated with the decommissioning of our nuclear power plants Calvert Cliffs Nuclear Power Plant (Calvert Cliffs), Nine Mile Point Nuclear Station (Nine Mile Point) and R. E. Ginna Nuclear Power Plant (Ginna). Upon the close of the transaction with EDF on November 6, 2009, we deconsolidated CENG and removed the asset retirement obligations associated with these nuclear power plants from our Consolidated Balance Sheets. Our remaining asset retirement obligations are associated with our other generating facilities and certain other long-lived assets.

From time to time, we will perform studies to update our asset retirement obligations. We record a liability when we are able to reasonably estimate the fair value of any future legal obligations associated with retirement that have been incurred and capitalize a corresponding amount as part of the book value of the related long-lived assets.

The increase in the capitalized cost is included in determining depreciation expense over the estimated useful lives of these assets. Since the fair value of the asset retirement obligations is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period to "Accretion of asset retirement obligations" in our Consolidated Statements of Income (Loss) until the settlement of the liability. We record a gain or loss when the liability is settled after retirement for any difference between the accrued liability and actual costs.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

Our nonregulated businesses capitalize interest costs for costs incurred to finance our power plant construction projects, real estate developed for internal use, and other capital projects.

Allowance for Funds Used During Construction (AFC)

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

The AFC rates for the period January 1, 2010 through December 3, 2010 were 9.40% for electric distribution plant, 8.47% for electric transmission plant, 8.49% for gas plant, and 9.08% for common plant. The AFC rates for the period December 4, 2010 through December 31, 2010 were 8.06% for electric distribution plant, 8.47% for electric transmission plant, 7.90% for gas plant, and 8.07% for common plant. BGE compounds AFC annually.

Long-Term Debt and Credit Facilities

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

In addition to the fees that are paid upfront for credit facilities, we also incur ongoing fees related to these facilities. We record the ongoing fees in other (expense) income, and we record interest incurred on cash draws in interest expense.

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

Accounting Standards Adopted

Accounting for Variable Interest Entities

In June 2009, the FASB amended the accounting, presentation, and disclosure guidance related to variable interest entities.

The amended standard includes the following significant provisions:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- requires the entity that consolidates a VIE (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

We adopted this guidance on January 1, 2010 and, as a result of our assessment and implementation of the new requirements, our accounting and disclosures related to VIEs were impacted as follows:

- We have presented separately on our Consolidated Balance Sheets, to the extent material, the assets of our consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit.
- The new requirements emphasize a qualitative assessment of whether the equity holders of the entity have the power to direct matters that most significantly impact the entity. We have evaluated all existing entities under the new VIE accounting requirements, both those previously considered VIEs and those considered potential VIEs. Our accounting for and disclosure about VIEs did not change materially as a result of these assessments.

We discuss our investments in variable interest entities in more detail in *Note 4*.

Noncontrolling Interests in Consolidated Financial Statements

Effective January 1, 2009, we adopted guidance relating to the accounting and reporting of noncontrolling interests in consolidated financial statements. We presented and disclosed our noncontrolling interests in our Consolidated Financial Statements, and we accounted for the 2009 sale of a 49.99% membership interest in CENG to EDF by deconsolidating CENG, measuring our retained interest at fair value, and recognizing a gain at closing. We discuss this transaction in more detail in *Note 2*.

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2 Other Events

2010 Events

		Pre-Tax		After-Tax
		(In millions)		
Impairment losses and other costs	$	**(2,476.8)**	$	**(1,487.1)**
International coal contract dispute settlement		**56.6**		**35.4**
Deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits				**(8.8)**
Amortization of basis difference in CENG		**(195.2)**		**(117.5)**
Loss on early retirement of 2012 Notes		**(51.6)**		**(30.9)**
Impact of power purchase agreement with CENG		**(185.6)**		**(113.3)**
Gain on divestitures		**240.0**		**146.0**
Total other items	$	**(2,612.6)**	$	**(1,576.2)**

Impairment Losses and Other Costs

Impairment Evaluations

We discuss our policy for evaluation of assets for impairment and other than temporary declines in value in *Note 1*. We perform impairment evaluations for our long-lived assets, equity method and cost method investments, and goodwill when events occur that indicate that the potential for an impairment exists.

During the third quarter of 2010, the following events resulted in the need for us to perform impairment evaluations of our equity method investments as well as the power plants we own:

- commodity prices declined substantially,
- there was a decrease in certainty around the timing and extent of environmental legislation,
- we completed a process that led us to reject the terms and conditions of a Department of Energy (DOE) loan guarantee related to the development of a new nuclear power plant, and
- with respect to our investments in UNE and CENG, certain contractual issues with our partner remained unresolved as of the end of the third quarter of 2010.

As a result of these evaluations, we recorded impairments of several of our equity method investments. We describe the impairment evaluations we performed in the following sections.

Equity Method Investments

We evaluated certain of our equity method investments in light of recent declines in commodity prices and the completion of the process that led to our rejection of the terms and conditions of the DOE loan guarantee for the development of new nuclear assets. The investments we evaluated include our investment in CENG, our investment in UNE, and our investments in certain qualifying facilities.

We record an impairment if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary." We do not record an impairment if the decline in value is temporary and we have the ability to recover the carrying amount of our investment. In making this determination, we evaluate the reasons for an investment's decline in value, the extent and length of that decline, and factors that indicate whether and when the value will recover.

CENG

As of September 30, 2010, the estimated fair value of our investment in CENG was $2.9 billion, which was lower than its carrying value of $5.2 billion. The carrying value of our investment reflected fair value as of the November 9, 2009 closing of EDF's investment in CENG. At that time, we were required to deconsolidate CENG and record our retained investment at fair value. We describe this transaction in more detail in *Note 16*.

There is no active market for the ownership interests in CENG or comparable entities that solely own and operate nuclear power plants. Therefore, we were required to exercise significant judgment in estimating the fair value of our investment based upon information that a market participant would consider. We believe our estimate incorporates the best data available as of September 30, 2010 for each input, which we describe below. However, the resulting fair value amount remains an estimate and is subject to change in the future based upon changes in any of the inputs or the underlying operating, market, and economic conditions we considered.

Because of the absence of relevant market transactions for similar entities, we estimated the fair value of CENG using discounted future cash flows based upon inputs that we believe reflect a market participant's perspective. Our methodology was consistent with the methodology used to estimate fair value in November 2009. The most significant inputs to our estimate of fair value include expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments and a discounting factor reflective of an investor's required risk-adjusted return. To the extent possible, we considered available market information and other third-party data for each of the inputs. However, because of the long operating lives of nuclear power plants, we were required to estimate inputs for many years beyond periods for which observable market data is available. Additionally, we compared the inputs to relevant historical information, and we benchmarked our valuation using implied market data of other companies that own nuclear generation facilities.

Upon completion of our evaluation, we determined that the fair value of our investment in CENG had declined by approximately $2.3 billion on a pre-tax basis as of September 30, 2010. The decline in fair value is primarily attributable to the following factors:

- significant declines in power prices, particularly in the third quarter of 2010,

- decreases in the market price of natural gas that adversely impact the level of and potential for recovery in power prices in the near term,
- uncertainty regarding the timing and provisions of carbon and other potential environmental legislation negatively impacting estimated future power prices, and
- an increase in the discount rate reflecting higher risk-adjusted required returns for nuclear power plants.

Based upon the extent of the decline below carrying value, the fundamental reasons for the decline, and our assessment that a sufficient improvement in these factors necessary to produce a recovery in fair value is not likely to occur in the near term, we determined that the decline is other than temporary. Therefore, we recorded an approximately $2.3 billion pre-tax impairment charge during the quarter ended September 30, 2010 to write-down our investment to fair value as of that date. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). To the extent that the fair value of our investment declines further in future quarters, we may record additional write-downs if we determine that any additional declines are other than temporary.

UNE

As of September 30, 2010, the estimated fair value of our investment in UNE was zero as compared to its carrying value of $143.4 million.

Prior to the third quarter of 2010, we believed that we would recover our investment in UNE through the development and operation of a new nuclear power plant. However, during the third quarter of 2010, several factors led to a decline in the fair value of our investment, including:

- economics of nuclear baseload generation had deteriorated substantially for reasons described above for CENG, and
- we were unable to negotiate acceptable loan guarantee terms, culminating a process that led us to reject the DOE loan guarantee due to an uneconomic level of costs.

As a result of evaluating these factors, we determined that, as of September 30, 2010, we would not be able to recover the value of our investment. Our determination was based primarily on market-related factors that indicated that a market participant would assign little or no value to this entity due to the absence of a DOE loan guarantee.

We also evaluated whether this decline in fair value was temporary. Based upon the nature of the factors leading to the decline, we determined, at September 30, 2010, that it was unlikely that these matters would be resolved in the near term in a way that would permit recovery in the fair value of our investment. Therefore, we concluded that the decline in the value of our investment in UNE was other than temporary, and we recorded a $143.4 million pre-tax impairment charge during the quarter ended September 30, 2010 to write-down our investment to estimated fair value as of that date. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss).

Qualifying Facilities

As a result of the significant declines in power prices during the third quarter of 2010, we determined that the fair values of three of our equity method investments in coal-fired generating plants in California declined substantially below book value. As a result, we recorded a $50.0 million pre-tax impairment charge during the quarter ended September 30, 2010 to write down our investments to fair value as of that date.

Additionally, as a result of a sale of an ownership interest by our partner in the fourth quarter of 2010, we recorded an $8.4 million pre-tax impairment charge on one other equity method investment in California at December 31, 2010. We recorded these charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss).

Generating Plants

We evaluated the impact of the events that occurred during the third quarter of 2010 on the recoverability of our generating plants. As discussed in *Note 1*, we evaluated whether these plants would generate undiscounted cash flows from operations that are at least sufficient to recover the carrying value of our investment. Based upon our consideration of these events, the primary impact of which is a reduction in power prices, and the status of the generating plants' activities, we determined that our generating plants were not impaired as of September 30, or December 31, 2010.

Goodwill

We performed our annual impairment review in the quarter ended September 30, 2010 and determined that our goodwill is not impaired.

International Coal Contract Dispute Settlement

During 2010, we finalized the settlement of a contract dispute with a third party international coal supplier recognizing net pre-tax earnings of $56.6 million. We divested the majority of our international commodities operations in 2009.

Deferred Income Tax Expense Relating to Federal Subsidies for Providing Post-Employment Prescription Drug Benefits

During March 2010, the Patient Protection and Affordable Care Act and the Healthcare and Education Reconciliation Act of 2010 were signed into law. These laws eliminate the tax exempt status of drug subsidies provided to companies under Medicare Part D after December 31, 2012. As a result of this new legislation, we recorded a noncash charge to reflect additional deferred income tax expense of $8.8 million in March 2010.

Amortization of Basis Difference in CENG

On November 6, 2009, Constellation Energy sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we ceased to have a controlling financial interest in CENG and deconsolidated CENG in the fourth quarter of 2009.

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On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We had an initial basis difference of approximately $3.9 billion between the initial carrying value of our investment in CENG and our underlying equity in CENG. This basis difference was caused by the requirement to record our investment in CENG at fair value at closing while CENG's assets and liabilities retained their carrying value. We are amortizing this basis difference over the respective useful lives of the assets of CENG or as those assets impact the earnings of CENG.

Beginning in the fourth quarter of 2010, the amortization of the basis difference in CENG is lower as the basis difference was reduced by the amount of the impairment charge recorded on our investment in CENG during the quarter ended September 30, 2010. The new basis difference as of September 30, 2010 is $1.5 billion.

For the year ended December 31, 2010, we recorded $195.2 million of pre-tax basis difference amortization as a reduction to our equity investment earnings in CENG. We discuss the components of our equity investment earnings in *Note 4*.

Loss on Early Retirement of 2012 Notes

In February 2010, we retired an aggregate principal amount of $486.5 million of our 7.00% Notes due April 1, 2012 as part of a cash tender offer, at a premium of approximately 11%. We recognized a pre-tax loss on this transaction of $51.6 million within "Interest Expense" on our Consolidated Statements of Income (Loss).

Impact of Power Purchase Agreement with CENG

In connection with the closing of the CENG membership sale transaction with EDF, we entered into a five year power purchase agreement (PPA) with CENG with an initial fair value of $0.8 billion.

Based on energy prices at the time of closing of the EDF transaction, we recorded the approximately $0.8 billion "Unamortized energy contract asset" for the value of our PPA with CENG, and CENG recorded an approximately ($0.8) billion "Unamortized energy contract liability." Both entities are amortizing these amounts over the initial two years of the five-year term of the PPA, with the total net economic value to be realized by us in the form of lower purchased power costs equal to approximately $0.4 billion as a result of our 50.01% ownership interest in CENG. During 2010, we realized approximately $185.6 million pre-tax in economic value relating to its PPA with CENG.

Divestitures

BGE

In January 2010, BGE completed the sale of its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party. BGE received net cash proceeds of $20.9 million. No gain or loss was recorded on this transaction in 2010. BGE has no further involvement in the activities of this entity.

Mammoth Lakes Geothermal Generating Facility

In August 2010, we completed the sale of our 50% equity interest in the Mammoth Lakes geothermal generating facility in California. We received net cash proceeds of approximately $72.5 million. In the third quarter of 2010, our Generation business recorded a $38.0 million pre-tax gain on this transaction. We will have no further involvement in the activities of this generating facility.

Comprehensive Agreement with EDF

In November 2010, we closed on the comprehensive agreement with EDF that restructured the relationship between Constellation Energy and EDF, eliminated the outstanding asset put arrangement, and transferred to EDF the full ownership of UNE. We received approximately $140 million of cash, and $75.2 million of Constellation Energy common stock and recorded a $202.0 million pre-tax gain on this transaction. We discuss the comprehensive agreement with EDF in *Note 4*.

Quail Run Energy Center

In December 2010, we signed an agreement to sell our Quail Run Energy Center, a 550 MW natural gas plant in west Texas, to High Plains Diversified Energy Corporation (HPDEC) for $185.3 million. This agreement is contingent upon HPDEC obtaining financing through the sale of municipal bonds.

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2009 Events

	Pre-Tax	After-Tax
	(In millions)	
Gain on sale of 49.99% membership interest in our nuclear generation and operation business (CENG) to EDF	$ **7,445.6**	$ **4,456.1**
Amortization of basis difference in CENG	**(29.6)**	**(17.8)**
Net loss on divestitures	**(468.8)**	**(293.2)**
Impairment losses and other costs (1)	**(124.7)**	**(96.2)**
Impairment of nuclear decommissioning trust assets through November 6, 2009	**(62.6)**	**(46.8)**
Loss on redemption of Zero Coupon Senior Notes	**(16.0)**	**(10.0)**
Maryland PSC order BGE residential customer credits	**(112.4)**	**(67.1)**
Merger termination and strategic alternatives costs	**(145.8)**	**(13.8)**
Workforce reduction costs	**(12.6)**	**(9.3)**
Total other items	$ **6,473.1**	$ **3,901.9**

(1) *After-tax amount net of noncontrolling interest.*

Gain on Sale of 49.99% Membership Interest in CENG to EDF

On December 17, 2008, we entered into an Investment Agreement with EDF under which EDF would purchase from us a 49.99% membership interest in CENG for $4.5 billion (subject to certain adjustments).

In October 2009, the Maryland PSC issued an order approving the sale of a 49.99% membership interest in CENG to EDF subject to the following conditions:

- Constellation Energy funded a one-time $100 per customer distribution rate credit for BGE residential customers totaling $112.4 million in the fourth quarter of 2009. Constellation made a $66 million equity contribution to BGE in December 2009 to fund the after-tax amount of the rate credit as ordered by the Maryland PSC.

- Constellation Energy was required to make a $250 million cash capital contribution to BGE by no later than June 30, 2010. Constellation Energy made this contribution in December 2009.

- BGE will not pay common dividends to Constellation Energy if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the Maryland PSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade.

- BGE was authorized to file an electric distribution rate case at any time beginning in January 2010 and was ordered not to file a subsequent electric distribution rate case until January 2011. Any rate increase in the first electric distribution rate case was capped at 5% as agreed to by Constellation Energy in its 2008 settlement with the State of Maryland and the Maryland PSC. The timing of any gas distribution rate filing was to occur no earlier than the electric rate case.

- Constellation Energy was limited to allocating no more than 31% of its holding company costs to BGE until the Maryland PSC reviews such cost allocations in the context of BGE's next rate case.

- Constellation Energy and BGE implemented "ring fencing" measures in February 2010 designed to provide bankruptcy protection and credit rating separation of BGE from Constellation Energy. Such measures include the formation of a new special purpose subsidiary by Constellation Energy (RF HoldCo) to hold all of the common equity interests in BGE.

With the receipt of the Maryland PSC's order, Constellation Energy and EDF closed the transaction on November 6, 2009. Upon closing of the transaction, we sold a 49.99% membership interest in CENG to EDF for total consideration of approximately $4.7 billion (includes $3.5 billion in cash at close, the non-cash redemption of the $1.0 billion Series B Preferred Stock held by EDF, and certain expense reimbursements). As a result, we retained a 50.01% economic interest in CENG, but we and EDF have equal voting rights over the activities of

CENG. Accordingly, we deconsolidated CENG in the fourth quarter of 2009.

We recorded this transaction as follows:

- We received cash consideration of approximately $3.5 billion, plus certain adjustments, and redeemed the $1.0 billion Series B Preferred Stock held by EDF as additional purchase price resulting in net proceeds of approximately $4.7 billion.
- We removed the individual assets and liabilities of CENG from our balance sheet with a net asset value of approximately $2.4 billion.
- We recorded our retained investment in CENG at estimated fair value of approximately $5.1 billion.
- We recognized a pre-tax gain on sale of approximately $7.4 billion, calculated as follows:

	(In billions)
Fair value of the consideration received from EDF	$ 4.7
Estimated fair value of our retained interest in CENG	5.1
Carrying amount of CENG's assets and liabilities prior to deconsolidation	(2.4)
Pre-tax gain	$ 7.4

On November 6, 2009, we began to account for our retained investment in CENG using the equity method and report our share of its earnings in our Generation business segment. As a result, we no longer record the individual income statement line items, but instead record our share of the investment's earnings in a single line in our Consolidated Statements of Income (Loss).

We estimated the fair value of CENG for purposes of recording our retained interest upon closing of the sale. Our estimate considered the replacement cost, discounted future cash flows, and comparable market transactions valuation approaches. After correlating the valuations under these three approaches, the ultimate fair value estimate reflects the discounted future expected cash flows of the business using various inputs that we believe are reflective of a market participant's perspective. The most significant inputs include our expectations of nuclear plant performance, future power prices, nuclear fuel and operating costs, forecasted capital expenditures, existing power sales commitments, and a discounting factor reflective of an investor's required risk-adjusted return.

The fair value of our investment in CENG exceeded our share of CENG's equity because CENG's assets and liabilities retained their historical carrying value. This basis difference totaled approximately $3.9 billion, and we assigned it to the noncurrent assets of CENG based on fair value. We will amortize this difference as a reduction in our equity investment earnings in CENG as follows:

Difference	**Amortization Period**
Property, plant and equipment	Depreciable life
Power purchase agreements and revenue sharing agreements	Term of the agreement
Land and intangibles with indefinite lives	Upon sale by CENG

For the period November 6, 2009 through December 31, 2009, we recorded $29.6 million of basis difference amortization as a reduction to our equity investment earnings in CENG. We discuss the components of our equity investment earnings in *Note 4*.

Also, if we were to sell an additional portion of our investment, we would recognize a proportionate amount of the basis difference.

Divestitures

In 2009, we completed many of the strategic initiatives we identified in 2008 to improve liquidity and reduce our business risk.

The transactions to sell a majority of our international commodities, our Houston-based gas trading and other operations were structured in two parts:

- the assignment and transfer of a majority of the portfolio, and
- the execution of a Total Return Swap (TRS) mechanism for the remainder of the portfolio.

Under the TRS, we entered into offsetting trades with the buyers that matched the terms of the remaining third party contracts for which we were unable to complete assignment to the buyers as of the transaction dates. This structure transferred the risks associated with changes in commodity prices as of the transaction dates to the buyers in all instances. However, the trades under the TRS are newly executed transactions, and we remain the principal under both the unassigned third party trades and the matching trades with the buyers under the TRS with no right of either financial or legal offset. We continue to pursue the assignment of these remaining contracts to the buyers.

The matching contracts under the TRS include both derivatives and non-derivatives and were executed at prices that differed from market prices at closing, which resulted in a net cash payment to/from the buyers. We recorded the underlying contracts at fair value on a gross basis as assets or liabilities in our Consolidated Balance Sheets depending on whether the contract prices were above- or below-market prices at closing. As a result, the derivative contracts have been included in "Derivative Assets and Liabilities" and the nonderivative contracts have been included in "Unamortized Energy Contract Assets and Liabilities." The derivative contracts are subject to mark-to-market accounting until they are realized or assigned. The nonderivative contracts will be amortized into earnings as the underlying contracts are realized, or sooner if those contracts are assigned.

We record the cash proceeds we pay or receive at the inception of energy purchase and sale contracts based upon whether the contracts are in-the-money or out-of-the-money as follows:

In-the-money contracts proceeds paid	Investing Outflow
Out-of-the-money contracts proceeds received	Financing Inflow

After inception, we record the cash flows from all energy purchase and sale contracts as operating activities, except for out-of-the-money derivative contracts that were liabilities at inception. We record the ongoing cash flows from these out-of-the-money derivative contracts as financing activities, regardless of whether they are purchase or sale contracts.

International Commodities Operation

In January 2009, we entered into a definitive agreement to sell a majority of our international commodities operation. We completed this transaction on March 23, 2009 and recognized the following impacts during 2009:

- a pre-tax loss of approximately $334.5 million representing net consideration paid to the buyer, the book value of net assets sold, and transaction costs,
- a reclassification of $165.7 million in losses on previously designated cash-flow hedge contracts, for which the forecasted transactions are now deemed probable of not occurring, from "Accumulated Other Comprehensive Loss" to "Nonregulated revenues" in the Consolidated Statements of Income (Loss),
- workforce reduction costs of $10.9 million, recorded as part of "Workforce reduction costs" in the Consolidated Statements of Income (Loss), and
- other costs of $17.6 million related to leasehold improvements, furniture and computer hardware and software, recorded as part of "Impairment losses and other costs" in the Consolidated Statements of Income (Loss).

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We removed the contracts that were assigned from our balance sheet, paid the buyer approximately $90 million, and reflected the impact of this payment on our working capital in the operating activities section of our Consolidated Statements of Cash Flows.

The net cash payment to the buyer upon completion of the TRS was $2.5 million. As part of the consideration, we acquired matching nonderivative contracts that resulted in a net liability of approximately $75 million, which will be amortized into earnings as the underlying contracts are realized, or sooner if the original nonderivative contracts are assigned.

We have reflected the contracts under the TRS on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year Ended December 31, 2009

			(In millions)
Investing activities	Contract and portfolio acquisitions	**$**	**(866.3)**
Financing activities	Proceeds from contract and portfolio acquisitions		**863.8**
Net cash flows from contract and portfolio acquisitions		**$**	**(2.5)**

In addition to the March 23, 2009 transaction for a majority of our international commodities operation, on June 30, 2009 we completed the sale of a uranium market participant that we owned. We received cash proceeds of approximately $43 million and recorded a $27.2 million loss on this sale. This loss from our NewEnergy business segment is included in the "Net (loss) gain on divestitures" line in our Consolidated Statements of Income (Loss).

Houston-Based Gas and Other Trading Operations

On February 3, 2009, we entered into a definitive agreement to sell our Houston-based gas trading operation. We transferred control of this operation on April 1, 2009. In addition, in the second quarter of 2009 we also sold certain other trading operations. In total, we received proceeds of approximately $61 million, and recorded a $102.5 million net loss on these sales in 2009. The net loss on sale primarily relates to nonderivative accrual contracts, which were not recorded on our Consolidated Balance Sheet, the cost associated with disposing of an entire portfolio and not merely individual contracts, and the cost of capital, including contingent capital, to support the operation.

The matching derivative and nonderivative transactions under the TRS discussed above were executed at prices that differed from market prices at closing. As a result, we record the ongoing cash flows related to the out-of-the-money derivative contracts that were liabilities at inception as financing cash flows. This resulted in cash outflows related to financing activities of $858.5 million in our Consolidated Statements of Cash Flows for the year ended December 31, 2009 associated with derivative liabilities that were out-of-the-money.

The net cash receipt from the buyers upon completion of the TRS was $91.9 million in the second quarter of 2009. We have reflected these contracts on a gross basis in cash flows from investing and financing activities in our Consolidated Statements of Cash Flows as follows:

Year Ended December 31, 2009

			(In millions)
Investing activities	Contract and portfolio acquisitions	**$**	**(1,287.4)**
Financing activities	Proceeds from contract and portfolio acquisitions		**1,379.3**
Net cash flows from contract and portfolio acquisitions		**$**	**91.9**

In addition, we incurred other costs of $7.0 million for 2009 related to leasehold improvements, furniture, computer hardware and software costs, which are recorded as part of "Impairment losses and other costs" on our Consolidated Statements of Income (Loss).

On April 1, 2009, we executed an agreement with the buyer of our Houston-based gas trading operation under which the buyer will provide us with the gas supply needed to support our NewEnergy retail gas customer supply activities through March 31, 2011. This agreement was structured such that our requirements to post collateral are reduced. The supplier has liens on the assets of the retail gas supply business as well as our investment in the stock of these entities to secure our obligations under the gas supply agreement. In connection with this agreement, we posted approximately $160 million of collateral. This was subsequently reduced to $100 million. The initial $160 million posted represented approximately 25 percent of the previous collateral requirements to support this operation.

Shipping Joint Venture

We completed the sale of our equity investment in a shipping joint venture during the third quarter of 2009. No gain or loss was recognized on the sale. We discuss the sale of the shipping joint venture below.

Other Nonregulated Divestiture

During the fourth quarter of 2009, one of our nonregulated subsidiaries sold an energy project and recorded a net loss of $4.6 million.

Impairment Losses and Other Costs

We discuss our evaluation of assets for impairment and other than temporary declines in value in *Note 1*. We perform impairment evaluations for our long-lived assets, equity method investments, and goodwill when triggering events occur that indicate the potential for an impairment exists.

Available for Sale Securities

We evaluated certain of our investments in equity securities during 2009. The investments we evaluated included our nuclear decommissioning trust fund assets (through November 6, 2009)

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and other marketable securities. We record an impairment charge if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is "other than temporary."

In making this determination, we evaluate the reasons for an investment's decline in value, the extent and duration of that decline, and factors that indicate whether and when the value will recover. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value is considered other than temporary and we write them down to fair value. We discuss our impairment policy in more detail in *Note 1*.

The fair values of certain of the securities held in our nuclear decommissioning trust fund held through November 6, 2009 and other marketable securities declined below book value. As a result, we recorded a $62.6 million pre-tax impairment charge for the year ended December 31, 2009 for our nuclear decommissioning trust fund assets in the "Other income (expense)" line in our Consolidated Statements of Income (Loss). We also recorded an impairment charge of $0.5 million for other marketable securities not included in our nuclear decommissioning trust funds for the year ended December 31, 2009.

The estimates we utilize in evaluating impairment of our available for sale securities require judgment and the evaluation of economic and other factors that are subject to variation, and the impact of such variations could be material.

Equity Method Investments

Shipping Joint Venture

We record an impairment if an equity method investment has experienced a decline in fair value to a level less than our carrying value and the decline is other than temporary. During the quarter ended June 30, 2009, we contemplated several potential courses of action together with our partner relating to the strategic direction of our shipping joint venture and our continuing involvement. This led to a decision to explore a plan to sell our 50% interest to a party related to our joint venture partner for negligible proceeds. We completed the sale of this investment in the third quarter of 2009. We have no further involvement in the activities of the joint venture.

As a result of the events that occurred during the second quarter of 2009, we concluded that the fair value of our investment had declined to a level below the carrying value at June 30, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $59.0 million associated with our equity investment in our shipping joint venture within the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss), and reported the charge in our NewEnergy business segment results for 2009.

Constellation Energy Partners LLC

As of March 31, 2009, the fair value of our investment in Constellation Energy Partners LLC (CEP) based upon its closing unit price was $10.0 million, which was lower than its carrying value of $24.0 million.

The decline in fair value of our investment in CEP at that time reflected a number of factors, primarily including difficulties in the financial and credit markets and the decreases in the market price of natural gas and oil.

As a result of evaluating these factors, we determined that the decline in the value of our investment is other than temporary. Therefore, we recorded a $14.0 million pre-tax impairment charge at March 31, 2009 to write-down our investment to fair value. We recorded this charge in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). We did not record an impairment charge for the remainder of 2009.

District Chilled Water

During 2009, BGE entered into an agreement to sell its interest in a nonregulated subsidiary that owns a district chilled water facility to a third party. We completed this sale in January 2010. We have no further involvement in the activities of this entity.

As a result of these events, we concluded that the fair value of our investment in this subsidiary had declined to a level below carrying value at December 31, 2009 and that this decline was other than temporary. As such, we recorded a pre-tax impairment charge of $12.0 million, net of the noncontrolling interest impact of $8.0 million. The gross impairment charge of $20.0 million is recorded within the "Impairment losses and other costs" line in both our and BGE's Consolidated Statements of Income (Loss). The noncontrolling interest portion of $8.0 million is recorded within the "Net Income Attributable to Noncontrolling Interests and BGE Preference Stock Dividends" line in our Consolidated Statements of Income (Loss) and within the "Net Income Attributable to Noncontrolling Interests" line in BGE's Consolidated Statements of Income.

Other Costs

During 2009, we recorded $31.2 million pre-tax charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss) primarily related to:

- divested operations long-lived assets no longer used and lease terminations, and
- the write-off of an uncollectible advance to an affiliate.

Loss on Redemption of Zero Coupon Senior Notes

In November 2009, we redeemed the Zero Coupon Senior Notes early and recognized a pre-tax loss on redemption of $16.0 million within "Interest Expense" on our Consolidated Statements of Income (Loss).

Merger Termination and Strategic Alternatives Costs

We incurred additional costs during 2009 related to the terminated merger agreement with MidAmerican, the transactions related to EDF, and other strategic alternatives costs. These costs totaled $145.8 million pre-tax for the year ended December 31, 2009, and primarily relate to fees incurred to complete the transactions with EDF and the first quarter of 2009 write-off of the unamortized debt discount associated with the 14% Senior Notes (Senior Notes) that were repaid in full to MidAmerican in January 2009. Upon the closing of the

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transaction with EDF on November 6, 2009, certain of the costs incurred in 2008 and 2009 became tax deductible. We reflected this impact in 2009.

Workforce Reduction Costs

We incurred workforce reduction costs during the fourth quarter of 2008, primarily related to workforce reduction efforts across all of our operations (Q4 2008 Program), and during the first quarter of 2009, primarily related to the divestiture of a majority of our international commodities operation as well as some smaller restructurings elsewhere in our organization (Q1 2009 Program). For the Q1 2009 Program, we recognized a $12.6 million pre-tax charge during 2009 related to the elimination of approximately 180 positions. We substantially completed these workforce reductions during 2010.

The following table summarizes the status of the involuntary severance liabilities at December 31, 2009:

	Q1 2009 Program	Q4 2008 Program
	(In millions)	
Initial severance liability balance	$ 10.8	$ 19.7
Additional expenses recorded in 2009	1.8	
Amounts recorded as pension and postretirement liabilities		(3.0)
Net cash severance liability	12.6	16.7
Cash severance payments	(12.0)	(15.8)
Severance liability balance at December 31, 2009	$ 0.6	$ 0.9

2008 Events

	Pre-Tax	After-Tax
	(In millions)	
Merger termination and strategic alternatives costs	**$ (1,204.4)**	**$ (1,204.4)**
Impairment losses and other costs	**(741.8)**	**(470.7)**
Workforce reduction costs	**(22.2)**	**(13.4)**
Emissions allowances write-down	**(46.7)**	**(28.7)**
Net gain on divestitures	**25.5**	**16.0**
Gain on sale of dry bulk vessel	**29.0**	**18.9**
Maryland settlement credit (after-tax amount reflects the effective tax rate impact on BGE)	**(189.1)**	**(110.5)**
Impairment of nuclear decommissioning trust assets	**(165.0)**	**(82.0)**
Total other items	**$ (2,314.7)**	**$ (1,874.8)**

Merger Termination and Strategic Alternatives Costs

We incurred costs during 2008 related to the terminated merger agreement with MidAmerican, the conversion of Series A Preferred Stock, the execution of the Investment Agreement and related agreements with EDF, and our pursuit of other strategic alternatives. These costs totaled $1.2 billion pre-tax. We did not record a tax benefit for any of these costs in our Consolidated Statement of Income (Loss) in 2008.

A significant portion of these costs was incurred pursuant to the termination of the merger agreement with MidAmerican and the conversion of the Series A Preferred Stock. Specifically, Constellation Energy incurred the following charges:

- $175 million merger termination fee,
- approximately $945 million for settling the conversion of the Series A Preferred Stock, which included a cash payment of $418 million and issuance of approximately 19.9 million shares of our common stock,

- approximately $15 million for the remaining unamortized portion of the premium paid as part of executing an agreement with MidAmerican in November 2008 that provided us the option to sell certain generating plants to MidAmerican for aggregate proceeds of $350 million. This agreement was terminated as part of the termination of our merger agreement with MidAmerican, and

- approximately $70 million in other costs associated with the MidAmerican transaction and other strategic alternatives explored consisting primarily of external legal, accounting and consulting fees.

The above amounts do not include $150 million of cash received from EDF in conjunction with the Investment Agreement entered into on December 17, 2008. We recorded this $150 million as additional purchase price at closing.

BGE recorded $16 million as its allocable portion of these costs through November 30, 2008 when the merger with MidAmerican was still pending. However, in light of the EDF transaction involving an investment in our nonregulated nuclear generation and operation business rather than a merger with Constellation Energy, BGE was not allocated any further costs effective in December 2008 and all of the previously allocated costs recorded by BGE were allocated to the Generation and NewEnergy segments.

Impairment Losses and Other Costs

Impairment Evaluations

We discuss our evaluation of assets for impairment and other than temporary declines in value in *Note 1*. We perform impairment evaluations for our long-lived assets, equity method investments, and goodwill when triggering events occur that would indicate that the potential for an impairment exists. We perform an impairment evaluation for our nuclear decommissioning trust fund assets quarterly.

In addition, we evaluate goodwill for impairment on an annual basis regardless of whether any triggering events have occurred. Our accounting policy is to perform an annual goodwill impairment review in the third quarter of each year.

During the third quarter of 2008, the following triggering events resulted in the need for us to perform impairment analyses:

- we announced a strategic initiative to sell our upstream gas assets subject to market conditions,

- there was a significant decline in the availability of credit in the markets,

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- there was a significant decline in the overall stock market and, in particular, our stock price,
- we signed a definitive merger agreement with MidAmerican, which was subsequently terminated, and
- commodity prices declined substantially.

As a result of these evaluations, we recorded impairments of our upstream gas properties, goodwill, and certain investments in debt and equity securities. Additionally, in the fourth quarter of 2008, there were continued declines in commodity prices and the overall stock market. This led to further impairment of our upstream gas properties, and certain investments in debt and equity securities. We describe the impairment evaluations we performed in the following sections.

Long-Lived Assets

We evaluate potential impairment of long-lived assets classified as held for use and recognize an impairment loss if the carrying amount of such assets is not recoverable. The carrying amount of an asset held for use is not recoverable if it exceeds the total undiscounted future cash flows expected to result from the use and eventual disposition of the asset.

This evaluation requires us to estimate uncertain future cash flows. In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. The assumptions we use are consistent with forecasts that we make for other purposes (for example, in preparing our other earnings forecasts) or have been adjusted to reflect relevant subsequent changes. If we are considering alternative courses of action (such as the potential sale of an asset), we probability- weight the alternative courses of action to estimate the expected 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.

Upstream Gas Properties

During 2008, we performed impairment analyses for our upstream gas properties as a result of the following triggering events:

- we announced our intent to sell our upstream gas assets, and
- there were significant decreases in natural gas prices and oil prices in both the third and fourth quarters of 2008.

We evaluated both proved and unproved property for impairments. Unproved property is impaired if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance. To the extent that unproved property is part of an asset that contains proved property, we applied the accounting guidance for proved property for evaluating impairment.

During the third quarter of 2008, we began the process necessary to sell our upstream gas properties, and, while we sold some of these properties by December 31, 2008, we had not yet obtained the formal approval of our Board of Directors for the sale of our other remaining properties. This approval was required to commit to a plan for sale. As a result, we continued to classify these properties as held for use as of December 31, 2008. Accordingly, our impairment evaluation consisted of estimating expected undiscounted cash flows under various scenarios as discussed below and comparing those amounts to the carrying value.

We evaluated our upstream gas portfolio for impairment at the individual property level, which is the lowest level of identifiable cash flows, since each property has separate financial statements identifying and capturing the related cash flows. We evaluated a combination of cash flows from operations scenarios for the remaining period for which we expected to hold these properties as well as estimates of proceeds from each property's ultimate disposal. The primary inputs to our estimates of cash flows from operations were reserve estimates and natural gas and oil prices based upon forward curves and modeled data for unobservable periods. The primary inputs to our estimate of proceeds from disposal were a combination of external market bids, internal models and reserve reports, and information from external advisors assisting in the sale of these assets. We maximized the use of market information to the extent it was available. We evaluated several possible courses of action and timing, and we probability-weighted the cash flows associated with each of these scenarios based upon our best estimates of the expected outcome and timing in order to arrive at each property's expected future cash flows.

Our evaluation indicated that estimated cash flows were less than the carrying value of three of our seven upstream gas properties at September 30, 2008. At December 31, 2008, our evaluation indicated that estimated cash flows were less than the carrying value for two additional properties and for one property in which that property's estimated cash flows were less than its post-impairment carrying value at September 30, 2008 as well. The primary factors leading to the declines in expected cash flows were the decrease in market prices for natural gas and oil during the third and fourth quarters of 2008 combined with our expectation that we would sell these properties rather than hold them for their full useful lives.

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As a result, we recorded the following pre-tax impairment charges:

Asset Groups	At September 30, 2008	At December 31, 2008
	(In millions)	
Interest in proved and unproved natural gas and crude oil reserves in south Texas	$ 62.6	$
Interest in proved natural gas reserves in the Rocky Mountains	73.2	
Interest in proved and unproved natural gas reserves in the Offshore-Gulf of Mexico	7.1	3.8
Interest in proved and unproved crude oil and natural gas reserves in eastern Oklahoma		30.0
Interest in proved and unproved natural gas reserves in central Oklahoma		153.2
Total impairment charges	$ 142.9	$ 187.0

We recorded these impairment charges in the "Impairment losses and other costs" line in our Consolidated Statements of Income (Loss), and they are reported in our NewEnergy business segment results.

Generating Plants

We evaluated the impact of the events that occurred in 2008 on the recoverability of our generating plants. Based upon our consideration of these events and the status of the generating plant's activities, we determined that our generating plants were not impaired as of September 30, 2008 and December 31, 2008.

Debt and Equity Securities and Investments

We evaluated certain of our investments in debt and equity securities (both equity-method and cost-method investments) in light of declines in market prices during the third and fourth quarters of 2008. The investments we evaluated included our investment in CEP, other marketable securities, our nuclear decommissioning trust fund assets, and our investment in UNE. We record an impairment if an investment has experienced a decline in fair value to a level less than our carrying value and the decline is other than temporary. We do not record an impairment if the decline in value is temporary and we have the ability and intent to hold the investment until its value recovers.

In making this determination, we evaluate the reasons for an investment's decline in value, the extent and length of that decline, and factors that indicate whether and when the value will recover. For securities held in our nuclear decommissioning trust fund for which the market value is below book value, the decline in fair value for these securities is considered other than temporary and we write them down to fair value.

The fair value of our investment in CEP fell below carrying value at the end of August, and continued to decline through the end of 2008. As of September 30, 2008, the fair value of our investment in CEP based upon its closing unit price was $73 million, which was lower than its carrying value of $128 million. As of December 31, 2008, the fair value of our investment in CEP based upon its closing unit price was $17 million, which was lower than its carrying value at December 31, 2008 of $87 million.

While CEP's estimate of net asset value exceeded our carrying value, the decline in fair value of our investment in CEP at that time reflected a number of factors, primarily including difficulties in the financial and credit markets and the decreases in the market price of natural gas and oil.

As a result of evaluating these factors at both September 30, 2008 and December 31, 2008, we determined that the declines in the value of our investment at both dates were other than temporary. Therefore, we recorded a $54.7 million pre-tax impairment charge at September 30, 2008 and an additional $69.7 million pre-tax impairment charge at December 31, 2008 to write-down our investment to fair value. We recorded these charges in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss). To the extent that the market price of our investment declines further in future quarters, we may record additional write-downs if we determine that those additional declines are other than temporary.

As a result of significant declines in the stock market during 2008, the fair values of certain of our marketable securities and many of the securities held in our nuclear decommissioning trust fund declined below book value. As a result, we recorded impairment charges of $31.0 million and $122.0 million pre-tax at September 30, 2008 and December 31, 2008, respectively, for our nuclear decommissioning trust fund investments in the "Other (expense) income" line in our Consolidated Statements of Income (Loss). We had previously recorded impairment charges for our nuclear decommissioning trust fund at both March 31, 2008 and June 30, 2008, totaling $12.0 million pre-tax. We also recorded an impairment charge of $7.0 million pre-tax for certain of our other marketable securities in the fourth quarter of 2008. In addition, we recorded other changes in the fair value of our nuclear decommissioning trust fund assets that are not impaired in other comprehensive income.

We also evaluated the impact of the events that occurred in 2008 on the recoverability of our investment in UNE. Based upon our consideration of these events and the status of UNE's activities, we determined that our investment in UNE was not impaired as of December 31, 2008.

The estimates we utilize in evaluating impairment of our debt and equity securities require judgment and the evaluation of economic and other factors that are subject to variation, and the impact of such variations could be material.

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Goodwill

Goodwill is the excess of the purchase price of an acquired business over the fair value of the net assets acquired. We 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, in the third quarter of each year, we evaluate goodwill for impairment.

The primary judgment affecting our impairment evaluation is the requirement to estimate fair value of the reporting units to which the goodwill relates. We evaluate impairment at the reportable segment level, which is the lowest level in the organization that constitutes a business for which discrete financial information is available.

Prior to September 30, 2008, substantially all of our goodwill related to our merchant energy segment, one of our reportable segments at that time. The lack of observable market prices for the merchant energy segment required us to estimate fair value, which we determined on a preliminary basis using the income valuation approach by computing discounted cash flows, consistent with prior evaluations. Although our estimate of discounted cash flows exceeded the carrying value of the merchant energy segment, because our common stock continued to trade at a price less than carrying value for the entire company throughout the last half of September and all of October, we also estimated fair value for the merchant energy segment using current market price information.

The primary inputs and assumptions to our estimate of fair value based upon market information were as follows:

- the fair value of Constellation Energy based upon recent market prices of our common stock,
- the estimated fair value of BGE, and
- the estimated value of the agreements executed with MidAmerican.

Using this information, we deducted the estimated fair value of non-merchant energy segment businesses from the fair value of Constellation Energy as a whole in order to estimate the fair value of the merchant energy segment as of September 2008. Based upon this estimate, the fair value of the merchant energy segment was substantially less than its carrying value. The primary difference between this estimate and our modeled estimates using the discounted cash flow income approach is that the market price approach incorporated the market's valuation discount associated with our merchant energy segment due to its significant liquidity and collateral requirements. We believe that this was a more appropriate method for estimating fair value than the modeled valuation techniques because it incorporated observable market information to a greater extent, which reflects current market conditions, and because it required fewer and less subjective judgments and estimates than our modeled estimates.

As a final consideration during our September 2008 impairment evaluation, we also evaluated the circumstances surrounding MidAmerican's purchase of Constellation Energy and whether the current market price of our common stock should be considered to represent fair value for accounting purposes. While the transaction price for the purchase of Constellation Energy resulted from negotiations that occurred over an abbreviated period of time during which the Company was experiencing financial difficulty, ongoing trading of the stock at levels approximating the transaction price represented the market's present assessment of fair value in a liquid, active market. This is consistent with guidance issued by the Securities Exchange Commission Office of the Chief Accountant and FASB Staff on the determination of fair value in distressed markets.

Based on our evaluation of these alternative measures of fair value, we determined that the fair value of the merchant energy business segment was less than its carrying value. Therefore, in order to measure the potential impairment of goodwill, we estimated the fair value of the merchant energy segment's assets and liabilities. We determined that the fair value of its assets net of liabilities substantially exceeded the segment's total fair value, indicating that the merchant energy segment's goodwill was impaired as of September 30, 2008. Accordingly, we recorded a pre-tax charge of $266.5 million to write-off the entire balance of our merchant energy segment goodwill substantially all of which was recorded in the third quarter of 2008. This charge is recorded in "Impairment losses and other costs" in our Consolidated Statements of Income (Loss).

Other Costs

In September 2008, we entered into a non-binding agreement to settle a class action complaint that alleged a subsidiary's ash placement operations at a third party site damaged surrounding properties. In December 2008, the settlement was approved by the court. As a result of this agreement, we recorded a $14.0 million pre-tax charge net of an expected insurance recovery.

Workforce Reduction Costs

In September 2008, our NewEnergy business approved a restructuring of its workforce. We recognized a $2.5 million pre-tax charge during 2008 related to the elimination of approximately 100 positions associated with this restructuring. We substantially completed this workforce reduction during 2009.

During the fourth quarter of 2008, we approved a restructuring of the workforce across all of our operations. We recognized a $19.7 million pre-tax charge in 2008 related to the elimination of approximately 380 positions.

Emissions Allowances

The Clean Air Interstate Rule (CAIR) required states in the eastern United States to reduce emissions of sulfur dioxide (SO_2) and established a cap-and-trade program for annual nitrogen oxide (NO_x) emission allowances. On July 11, 2008, the United States Court of Appeals for the D.C. Circuit (the "Court") issued an opinion vacating CAIR, subject to petitions for rehearing. The Environmental Protection Agency (EPA) filed a petition for rehearing. On December 23, 2008, the Court reversed its earlier decision to revoke CAIR and allowed CAIR to remain in effect until it is replaced by a revised rule issued by the EPA that would preserve the environmental rules established by CAIR. The Court did not propose a deadline by which the

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EPA must correct the flaws identified with CAIR but it did state that it will accept petitions if the EPA does not remedy the problems previously identified in its July 11, 2008 opinion. The EPA proposed regulations in July 2010, which are pending final adoption.

As a result of the Court's December 2008 decision, the annual NO_x program became effective in 2009 as originally established by CAIR. In addition, since the December 2008 decision, market prices for 2009 NO_x allowances have increased significantly, with lesser increases shown in allowances for subsequent years. There was also an increase in trading volumes for annual NO_x. For the SO_2 program, the EPA will be required to issue a new rule that would replace the allowances issued under Title IV of the Clean Air Act with a new, reduced pool of allowances which would meet or exceed existing CAIR targets. Market prices for SO_2 allowances have also risen since the Court's decision.

We account for our emission allowance inventory at the lower of cost or market, which includes consideration of our expected requirements related to the future generation of electricity. The weighted-average cost of our 2008 SO_2 allowance inventory in excess of amounts needed to satisfy these requirements was greater than market value at June 30, 2008 and market prices decreased further for both SO_2 and annual NO_x emission allowances through September 30, 2008. After giving consideration to the Court's July 11, 2008 decision and the subsequent decline in the market price of these allowances, we recorded a write-down of our SO_2 allowance inventory totaling $22.1 million pre-tax to reflect the June 30, 2008 market prices. At September 30, 2008, we recorded an additional write-down of our SO_2 emission allowance inventory and recorded a write-down of our annual NO_x allowance inventory totaling $58.9 million to reflect the September 30, 2008 prices. These write-downs were recorded in the "Nonregulated revenues" line in our Consolidated Statements of Income (Loss). The third quarter 2008 write-down was partially offset by mark-to-market gains totaling $22.2 million pre-tax on derivative contracts for the forward sale of emission allowances. This gain reflects the impact of lower market prices on the value of those derivative contracts.

Due to the increases in SO_2 and NO_x emission allowance prices stemming from the December 23, 2008 Court ruling, we evaluated the value of our emissions allowances and determined that a partial reversal of prior interim period write-downs was appropriate. At December 31, 2008, we reversed $11.4 million of the second and third quarter of 2008 write-downs. The prices at December 31, 2008 create a new cost basis for SO_2 and annual NO_x emission allowances and cannot be further written-up in future periods. Our mark-to-market gains on derivative contracts for the forward sale of emission allowances were $0.7 million for the quarter ended December 31, 2008. We cannot predict the outcome of any further judicial, regulatory or legislative developments or their impact on the emission allowance markets.

Net Gain on Divestitures

On March 31, 2008, we sold our working interest in oil and natural gas producing properties in Oklahoma to CEP, a related party, and recognized a gain of $14.3 million, net of the minority interest gain of $0.7 million. We discuss this transaction in more detail in *Note 16.*

In addition, on June 30, 2008, our NewEnergy business sold a portion of its working interests in proved natural gas reserves and unproved properties in Arkansas to an unrelated party for total proceeds of $145.4 million, which is subject to certain purchase price adjustments. Our NewEnergy business recognized a $77.7 million pre-tax gain on this sale.

In December 2008, our NewEnergy business sold working interests in proved natural gas reserves in Wyoming, and our equity investment in certain entities that own interests in proved natural gas reserves and unproved properties in Texas and Montana to unrelated parties for total proceeds of $55.7 million, subject to certain purchase price adjustments. Our NewEnergy business recognized a $67.2 million pre-tax loss on these sales.

The net gain is included in "Net (Loss) Gains on Divestitures" line in our Consolidated Statements of Income (Loss).

Gain on Sale of Dry Bulk Vessel

On July 10, 2008, a shipping joint venture, in which our NewEnergy business has a 50% ownership interest, sold one of the six dry bulk vessels it owns. Our NewEnergy business recognized a $29.0 million pre-tax gain on this sale. The gain is included in "Nonregulated revenues" line in our Consolidated Statements of Income (Loss).

Maryland Settlement Agreement Customer Rate Credit

In March 2008, Constellation Energy, BGE and a Constellation Energy affiliate entered into a settlement agreement with the State of Maryland, the Maryland PSC and certain State of Maryland officials to resolve pending litigation and to settle other prior legal, regulatory and legislative issues. On April 24, 2008, the Governor of Maryland signed enabling legislation, which became effective on June 1, 2008. Pursuant to the terms of the settlement agreement:

Each party acknowledged that the agreements adopted in 1999 relating to Maryland's electric restructuring law are final and binding and the Maryland PSC will close ongoing proceedings relating to the 1999 settlement.

BGE provided its residential electric customers $189.1 million in the form of a one-time $170 per customer rate credit. We recorded a reduction to "Electric revenues" on our and BGE's Consolidated Statements of Income (Loss) during the second quarter of 2008 and reduced customers' bills by the amount of the credit between September and December 2008.

BGE customers are relieved of the potential future liability for decommissioning Calvert Cliffs Unit 1 and Unit 2, scheduled to occur no earlier than 2034 and 2036, respectively, and are no longer obligated to pay a total of $520 million, in 1993 dollars adjusted for inflation, pursuant to the 1999 Maryland PSC order

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regarding the deregulation of electric generation. BGE will continue to collect the $18.7 million annual nuclear decommissioning charge from all electric customers through 2016 and continue to rebate this amount to residential electric customers, as previously required by Senate Bill 1, which had been enacted in June 2006.

BGE resumed collection of the residential return portion of the SOS administrative charge, which had been eliminated under Senate Bill 1, on June 1, 2008 and will continue collection through May 31, 2010 without having to rebate it to all residential electric customers. This will total approximately $40 million over this period.

Any electric distribution base rate case filed by BGE would not result in increased distribution rates prior to October 2009, and any increase in electric distribution revenue awarded would be capped at 5% with certain exceptions. Any subsequent electric distribution base rate case could not be filed prior to August 1, 2010. The agreement does not govern or affect BGE's ability to recover costs associated with gas rates, federally approved transmission rates and charges, electric riders, tax increases or increases associated with standard offer service power supply auctions.

Effective June 1, 2008, BGE implemented revised depreciation rates for regulatory and financial reporting purposes. The revised rates reduced depreciation expense approximately $14 million in 2008 without impacting rates charged to customers.

Effective June 1, 2008, Maryland laws governing investments in companies that own and operate regulated gas and electric utilities were amended to make them less restrictive with respect to certain capital stock acquisition transactions.

Constellation Energy elected two independent directors to the Board of Directors of BGE within the required six months from the execution of the settlement agreement.

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3 Information by Operating Segment

Our reportable operating segments are Generation, NewEnergy, Regulated Electric, and Regulated Gas:

- Our Generation business includes:
  - a power generation and development operation that owns, operates and maintains fossil and renewable generating facilities, a fuel processing facility, qualifying facilities, and power projects in the United States,
  - an operation that manages certain contractually controlled physical assets, including generating facilities,
  - an interest in a nuclear generation joint venture (CENG) that owns, operates, and maintains five nuclear generating units, and
  - up until November 3, 2010, when we completed the sale of our ownership interest, an interest in a joint venture (UniStar Nuclear Energy, LLC (UNE)) to develop, own, and operate new nuclear projects in the United States.
- Our NewEnergy business includes:
  - full requirements load-serving sales of energy and capacity to utilities, cooperatives, and commercial, industrial, and governmental customers,
  - sales of retail energy products and services to residential, commercial, industrial, and governmental customers,
  - structured transactions and risk management services for various customers (including hedging of output from generating facilities and fuel costs) and trading in energy and energy-related commodities to facilitate portfolio management,
  - risk management services for our Generation business,
  - design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities for commercial, industrial, and governmental customers throughout North America, including energy performance contracting and energy efficiency engineering services,
  - upstream (exploration and production) natural gas activities, and
  - sales of home improvements, servicing of electric and gas appliances, and heating, air conditioning, plumbing, electrical, and indoor air quality systems, and providing electric and natural gas to residential customers in central Maryland.
- Our regulated electric business purchases, transmits, distributes, and sells electricity in central Maryland.
- Our regulated gas business purchases, transports, and sells natural gas in central Maryland.

Our Generation, NewEnergy, Regulated Electric, and Regulated Gas reportable segments are strategic businesses based principally upon regulations, products, and services that require different technologies and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. A summary of information by operating segment is shown in the table below.

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	Reportable Segments				Holding Company and Other		
	Generation	NewEnergy	Regulated Electric	Regulated Gas		Eliminations	Consolidated
				(In millions)			
2010							
Unaffiliated revenues	**$ 1,189.2**	**$ 9,692.6**	**$ 2,752.1**	**$ 704.9**	**$ 1.2**	**$**	**$ 14,340.0**
Intersegment revenues	**1,055.1**	**428.8**	**0.2**	**4.5**		**(1,488.6)**	
Total revenues	**2,244.3**	**10,121.4**	**2,752.3**	**709.4**	**1.2**	**(1,488.6)**	**14,340.0**
Depreciation, depletion, and amortization	**136.1**	**83.4**	**205.2**	**44.0**	**48.9**		**517.6**
Fixed charges	**142.0**	**3.0**	**106.3**	**24.0**	**(0.2)**	**2.7**	**277.8**
Income tax (benefit) expense	**(873.1)**	**106.5**	**72.6**	**24.5**	**3.8**		**(665.7)**
Net (loss) income (1)	**(1,255.3)**	**176.2**	**110.0**	**37.6**	**(0.3)**		**(931.8)**
Net (loss) income attributable to common stock	**(1,255.3)**	**138.6**	**99.8**	**34.6**	**(0.3)**		**(982.6)**
Segment assets	**9,789.6**	**3,836.2**	**5,287.4**	**1,379.9**	**858.0**	**(1,132.6)**	**20,018.5**
Capital expenditures	**327.4**	**127.2**	**499.1**	**103.0**			**1,056.7**
2009							
Unaffiliated revenues	$ 664.2	11,345.8	$ 2,820.7	$ 753.8	$ 14.3	$	$ 15,598.8
Intersegment revenues	2,110.0	163.4		4.5	0.1	(2,278.0)	
Total revenues	2,774.2	11,509.2	2,820.7	758.3	14.4	(2,278.0)	15,598.8
Depreciation, depletion, and amortization	176.8	82.5	218.1	44.0	67.7		589.1
Fixed charges	166.5	39.7	113.3	26.0	2.4	2.2	350.1
Income tax expense (benefit)	3,107.1	(179.1)	50.9	17.1	(9.2)		2,986.8
Net income (loss) (2)	4,766.7	(348.2)	79.1	25.5	(19.7)		4,503.4
Net income (loss) attributable to common stock	4,766.7	(402.3)	68.9	22.5	(12.4)		4,443.4
Segment assets	12,402.1	4,167.5	4,994.6	1,413.4	4,573.7	(4,006.9)	23,544.4
Capital expenditures	1,039.2	116.8	373.0	66.0			1,595.0
2008							
Unaffiliated revenues	$ 856.2	15,185.4	$ 2,679.5	$ 1,004.8	$ 16.0	$	$ 19,741.9
Intersegment revenues	2,102.3	666.3	0.2	19.2	0.1	(2,788.1)	
Total revenues	2,958.5	15,851.7	2,679.7	1,024.0	16.1	(2,788.1)	19,741.9
Depreciation, depletion, and amortization	174.3	118.7	184.2	43.7	62.3		583.2
Fixed charges	140.7	50.6	113.5	26.3	2.3	15.7	349.1
Income tax expense (benefit)	121.3	(226.0)	(4.9)	25.5	5.8		(78.3)
Net (loss) income (3)	(357.7)	(1,011.4)	11.1	40.4	(0.8)		(1,318.4)
Net (loss) income attributable to common stock	(357.7)	(994.2)	1.1	37.2	(0.8)		(1,314.4)
Segment assets (4)	11,205.9	7,063.5	4,583.1	1,392.4	3,431.6	(5,392.4)	22,284.1
Capital expenditures	1,445.2	315.8	388.0	74.0			2,223.0

(1)

Our Generation business recognized the following after-tax items: impairment charges on certain of our equity method investment of $1,487.1 million, loss on the early retirement of 2012 Notes of $30.9 million, amortization of the basis difference in CENG of $117.5 million, impact of the power purchase agreement with CENG of $113.3 million, gain on the sale of Mammoth Lakes geothermal generating facility of $24.7 million, and a gain on the comprehensive agreement with EDF of $121.3 million. Our NewEnergy business recognized earnings relating to an international coal supplier contract dispute settlement of $35.4 million. Our Generation, NewEnergy, regulated electric and holding company and other businesses recognized deferred income tax expense relating to federal subsidies for providing post-employment prescription drug benefits of $0.8 million, $0.1 million, $3.1 million, and $4.8 million, respectively. We discuss these items in more detail in Note 2.

(2)

Our Generation business recognized the following after-tax items: gain on sale of a 49.99% membership interest in CENG to EDF of $4,456.1 million, amortization of basis difference in investment in CENG of $17.8 million, loss on the early extinguishment of zero coupon senior notes of $10.0 million, merger termination and strategic alternatives costs of $9.7 million, and impairment charges of our nuclear decommissioning trust assets through

November 6, 2009 of $46.8 million. Our NewEnergy business recognized the following after-tax items: merger termination and strategic alternatives costs of $4.1 million, losses on divestitures, which include losses on the sales of the international commodities and gas trading operations, the reclassification of losses on previously designated cash-flow hedges from Accumulated Other Comprehensive Loss because the forecasted transactions are probable of not occurring, earnings that are no longer part of our core business, of $371.9 million, impairment losses and other costs of $84.7 million, and workforce reduction costs of $9.3 million. Our regulated electric and gas businesses recognized after-tax charges of $56.7 million and $10.4 million, respectively, for the accrual of a residential customer credit. Our holding company and other businesses recognized after-tax charges of $11.5 million for impairment losses and other costs. We discuss these items in more detail in Note 2.

(3)

Our Generation business recognized the following after-tax charges: workforce reduction costs of $3.7 million, merger termination and strategic alternatives costs of $742.3 million, impairment charges and other costs of $8.3 million, and an impairment charge of our nuclear decommissioning trust assets of $82.0 million. Our NewEnergy business recognized the following after-tax charges: impairment losses and other costs of $460.1 million, workforce reduction costs of $5.8 million, merger termination and strategic alternatives costs of $462.1 million, net emission allowance write-down of $28.7 million, a net gain on the sale of upstream gas properties of $16.0 million, and a gain on sale of a dry bulk vessel of $18.9 million. Our regulated electric business recognized after-tax charges related to workforce reduction costs of $2.8 million and the Maryland settlement credit of $110.5 million. Our regulated gas business recognized an after-tax charge related to workforce reduction costs of $1.0 million. Our holding company and other businesses recognized an after-tax charge related to workforce reduction costs of $0.1 million. We discuss these items in more detail in Note 2.

(4)

At December 31, 2008, Holding Company and Other Businesses segment assets include approximately $1.6 billion of intercompany receivables, primarily relating to the allocation of merger termination costs of approximately $1.2 billion to these businesses, and $1.0 billion of restricted cash related to the issuance of Series B Preferred Stock to EDF. These funds are held at the holding company and are restricted for payment of the 14% Senior Notes held by MidAmerican. The 14% Senior Notes were repaid in full in January 2009.

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4 Investments

Investments in Joint Ventures, Qualifying Facilities and Power Projects, and CEP

Investments in joint ventures, qualifying facilities, domestic power projects, and CEP consist of the following:

At December 31,	2010	2009
	(In millions)	
Joint Ventures:		
CENG	**$ 2,991.1**	$ 5,222.9
UNE		122.0
Qualifying facilities and domestic power projects:		
Coal	**65.0**	119.7
Hydroelectric	**46.3**	55.2
Geothermal		40.0
Biomass	**55.1**	56.2
Fuel Processing	**16.7**	24.3
Solar	**6.8**	6.9
Total	**$ 3,181.0**	$ 5,647.2

Investments in joint ventures, qualifying facilities, domestic power projects, and CEP were accounted for under the following methods:

At December 31,	2010	2009
	(In millions)	
Equity method	**$ 3,174.2**	$ 5,640.3
Cost method	**6.8**	6.9
Total	**$ 3,181.0**	$ 5,647.2

We are actively involved in our CENG nuclear joint venture, qualifying facilities and power projects. Our percentage voting interests in these investments accounted for under the equity method range from 20% to 50.01%. Equity in earnings of these investments is as follows:

Year ended December 31,	2010	2009	2008
		(In millions)	
CENG	**$ 218.8**	$ 33.9	$
Amortization of basis difference in CENG (see *Note 2* for more detail)	**(195.2)**	(29.6)	
Total equity investment earnings CENG (1)	**23.6**	4.3	
UNE	**(16.8)**	(24.7)	(5.9)
Shipping JV		(1.8)	37.4
CEP		(4.6)	7.7
Qualifying facilities and domestic power projects	**18.2**	20.7	37.2
Total equity investment earnings	**$ 25.0**	$ (6.1)	$ 76.4

(1)

For the years ended December 31, 2010 and 2009, total equity investment (losses) earnings in CENG include $2.0 million and $0.4 million, respectively, of expense related to the portion of cost of certain share-based awards that we fund on behalf of EDF.

We describe each of these investments below. Additionally, we recorded impairment charges on certain of our equity method investments. We discuss these impairment charges in *Note 2*.

Joint Ventures

CENG

On November 6, 2009, we completed the sale of a 49.99% membership interest in CENG, our nuclear generation and operation business, to EDF. As a result of this transaction, we deconsolidated CENG and began to record our 50.01% investment in CENG under the equity method of accounting. Because the transaction occurred on November 6, 2009, we recorded $4.3 million of equity investment earnings in CENG, which represents our share of earnings from CENG from November 6, 2009 through December 31, 2009, net of the amortization of the basis difference in CENG. The basis difference is the difference between the fair value of our investment in CENG at closing and our share of the underlying equity in CENG, because the underlying assets and liabilities of CENG were retained at their carrying value. See *Note 2* for a more detailed discussion.

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Summarized balance sheet information for CENG is as follows:

At December 31,	2010	2009
	(In millions)	
Current assets	**$ 507.4**	$ 513.0
Noncurrent assets	**4,583.0**	4,404.2
Current liabilities	**630.9**	556.9
Noncurrent liabilities	**1,338.7**	1,716.1

Summarized income statement information for CENG is as follows:

	For the Year Ended December 31, 2010	For the Period from November 6, 2009 through December 31, 2009
	(In millions)	
Revenues	**$ 1,575.3**	$ 217.6
Expenses	**1,174.5**	153.0
Income from operations	**400.8**	64.6
Net income	**441.6**	68.5

In future periods, we may be eligible for distributions from CENG in excess of our 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. We would record these distributions, if realized, in earnings in the period received.

Comprehensive Agreement with EDF

On October 26, 2010, we reached a comprehensive agreement with EDF that restructured the relationship between our two companies, eliminated the outstanding asset put arrangement, and transferred to EDF the full ownership of UNE. This comprehensive agreement was approved by the boards of directors of both Constellation Energy and EDF, and the transaction closed on November 3, 2010. The agreement includes the following significant terms:

- EDF acquired our 50% ownership interest in UNE. Upon completion of this transaction, EDF became the sole owner of UNE, and we no longer have responsibility for developing or financing new nuclear plants through UNE.
- We terminated our rights under the existing asset put arrangement and, as a result, did not sell any of our plants to EDF.
- EDF paid us $140 million in cash and transferred to us 2.4 million of the shares of Constellation Energy common stock that it owned (with a fair value of $72.4 million at the time of the noncash financing transfer).
- EDF relinquished its seat on our Board of Directors, and the existing investor agreement between the companies (which includes a "standstill" provision) was terminated.

Later in November 2010, EDF transferred to us 0.1 million shares of Constellation Energy common stock, with a fair value of $2.8 million, in a noncash financing, upon our registering EDF's remaining shares of Constellation Energy common stock with the Securities and Exchange Commission. This enables EDF to transfer its remaining shares without restriction. We recorded a total pre-tax gain of $202.0 million in the fourth quarter of 2010 related to the above aspects of our comprehensive agreement with EDF.

In addition, upon receipt of necessary approvals:

- CENG will transfer to UNE potential new nuclear sites at the Nine Mile Point and Ginna nuclear generating plants in New York State.
- EDF will transfer to us an additional 1.0 million of the shares of Constellation Energy common stock that it owns.

We and EDF will remain owners in CENG under the same ownership percentages Constellation Energy holding a 50.01% interest and EDF holding a 49.99% interest. Further:

The power purchase agreement between CENG and each of Constellation Energy and EDF was modified such that prospective purchases will be unit contingent through the end of its term in 2014. In addition, beginning on January 1, 2015 and continuing to the end of the life of the respective plants, we will purchase 50.01% of the output of CENG's nuclear plants and EDF will purchase 49.99% of that output.

The administrative services agreement, which specifies payment to us for providing administrative support services to CENG, was extended through 2017.

We discuss the PPA and ASA in more detail in *Note 16*.

UNE

In August 2007, we formed a joint venture, UNE, with EDF to develop, own, and operate new nuclear projects in the United States and Canada. On November 3, 2010, we sold our 50% ownership interest in UNE to EDF. As a result of this transaction, EDF is the sole owner of UNE, and we will no longer have responsibility for developing or financing new nuclear plants through UNE.

Qualifying Facilities and Power Projects

Our Generation business holds up to a 50% voting interest in 15 operating domestic energy projects that consist of electric generation, fuel processing, or fuel handling facilities. Of these 15 projects, 13 are "qualifying facilities" that receive certain exemptions and pricing under the Public Utility Regulatory Policies Act of 1978 based on the facilities' energy source or the use of a cogeneration process.

CEP

In November 2006, CEP, a limited liability company formed by our NewEnergy business, completed an initial public offering. As of December 31, 2006, we owned approximately 54% of CEP and consolidated CEP. During the second quarter of 2007, CEP issued additional equity to the public and our ownership percentage fell below 50%. Therefore, we deconsolidated CEP and began accounting for our investment using the equity

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method. As of December 31, 2010, we hold a 28.5% voting interest in CEP.

Investments in Variable Interest Entities

As of December 31, 2010, we consolidated three VIEs in which we were the primary beneficiary, and we had significant interests in six VIEs for which we did not have controlling financial interests and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy- remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1.

BGE determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE, and we, consolidated BondCo.

The BondCo assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2010, 2009, and 2008, BGE remitted $90.3 million, $85.8 million, and $87.2 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2010 or 2009. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

During 2009, our NewEnergy business formed two new entities and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third party gas supplier. While we own 100% of these entities, we determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support we provide in the form of a letter of credit and a parental guarantee. We are the primary beneficiary of the retail gas entity group; accordingly, we consolidate the retail gas entity group as a VIE, including the existing retail gas customer supply operation, which we formerly consolidated as a voting interest entity.

The gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third party gas supply agreement before it can make any distributions to us,
- The third party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- As of December 31, 2010, we provided a $100 million parental guarantee and a $52 million letter of credit to the third party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee and the letter of credit, we do not have any contractual or other obligations to provide additional financial support to the retail gas entity group. The retail gas entity group creditors do not have any recourse to our general credit. Finally, we did not provide any financial support to the retail gas entity group during 2010, other than the equity contributions, parental guarantee and the letter of credit.

We also consolidate a retail power supply VIE for which we became the primary beneficiary in 2008 as a result of a modification to its contractual arrangements that changed the allocation of the economic risks and rewards of the VIE among the variable interest holders. The consolidation of this VIE did not have a material impact on our financial results or financial condition.

The carrying amounts and classification of the above consolidated VIEs' assets and liabilities included in our consolidated financial statements at December 31, 2010 and 2009 are as follows:

	2010	2009

	(In millions)	
Current assets	**$ 516.6**	$ 608.9
Noncurrent assets	**57.7**	67.7
Total Assets	**$ 574.3**	$ 676.6
Current liabilities	**$ 345.5**	$ 509.9
Noncurrent liabilities	**399.0**	420.3
Total Liabilities	**$ 744.5**	$ 930.2

All of the assets in the table above are restricted for settlement of the VIE obligations and all of the liabilities in the preceding table can only be settled using VIE resources.

During 2010, as part of the 2009 order from the Maryland PSC approving our transaction with EDF, we created RF HoldCo LLC, a bankruptcy-remote special purpose subsidiary to hold all of the common equity interests in BGE. This subsidiary is not a VIE. However, due to our ownership of 100% of the voting interests of RF HoldCo LLC, we consolidate this subsidiary as a voting interest entity.

BGE and RF HoldCo are separate legal entities and are not liable for the debts of Constellation Energy. Accordingly, creditors of Constellation Energy may not satisfy their debts from the assets of BGE and RF HoldCo except as required by applicable law or regulation. Similarly, Constellation Energy is not liable for the debts of BGE or RF HoldCo. Accordingly, creditors of BGE and RF HoldCo may not satisfy their debts from the assets of Constellation Energy except as required by applicable law or regulation.

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Unconsolidated Variable Interest Entities

As of December 31, 2010 and 2009, we had significant interests in six VIEs for which we were not the primary beneficiary. Other than the obligations listed in the table below, we have not provided any material financial or other support to these entities during 2010 or 2009.

The nature of these entities and our involvement with them are described in the following table:

VIE Category	Nature of Entity Financing	Nature of Constellation Energy Involvement	Obligations or Requirement to Provide Financial Support	Initial Date of Involvement
Power contract monetization entities (2 entities)	Combination of debt and equity financing	Power sale agreements, loans, and guarantees	$24.9 million and $34.7 million in letters of credit at December 31, 2010 and 2009, respectively	March 2005
Power projects and fuel supply entities (4 entities)	Combination of debt and equity financing	Equity investments and guarantees	$5.0 million and $2.0 million debt guarantee and working capital funding at December 31, 2010 and 2009, respectively	Prior to 2003

For purposes of aggregating the various VIEs for disclosure, we evaluated the risk and reward characteristics for, and the significance of, each VIE. We discuss in greater detail the nature of our involvement with the power contract monetization VIEs in the *Power Contract Monetization VIEs* section below.

We concluded that power over the most economically significant activities of two of the power project VIEs is shared equally among the equity holders. Accordingly, neither of the equity holders consolidates these VIEs. The equity holders own 50% interests in these VIEs and all of the significant decisions require the mutual consent of the equity holders.

The following is summary information available as of December 31, 2010 about these entities:

	Power Contract Monetization VIEs	All Other VIEs	Total
	(In millions)		
Total assets	$ 492.9	$ 288.3	$ 781.2
Total liabilities	382.6	113.2	495.8
Our ownership interest		48.7	48.7
Other ownership interests	110.3	126.4	236.7
Our maximum exposure to loss	24.9	46.4	71.3
Carrying amount and location of variable interest on balance sheet:			
Other investments		41.4	41.4

The following is summary information available as of December 31, 2009 about these entities:

	Power Contract Monetization VIEs	All Other VIEs	Total
	(In millions)		
Total assets	$ 568.3	$ 338.6	$ 906.9

Total liabilities	460.4	77.9	538.3
Our ownership interest		62.6	62.6
Other ownership interests	107.9	198.1	306.0
Our maximum exposure to loss	34.7	64.6	99.3
Carrying amount and location of variable interest on balance sheet:			
Other investments		62.6	62.6

Our maximum exposure to loss is the loss that we would incur in the unlikely event that our interests in all of these entities were to become worthless and we were required to fund the full amount of all guarantees associated with these entities. Our maximum exposure to loss as of December 31, 2010 and 2009 consists of the following:

- outstanding receivables, loans, and letters of credit totaling zero and $34.7 million, respectively,
- the carrying amount of our investment totaling $41.4 million and $62.6 million, respectively, and
- debt and payment guarantees totaling $29.9 million and $2.0 million, respectively.

We assess the risk of a loss equal to our maximum exposure to be remote and, accordingly have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would affect the fair value or risk of our variable interests in these variable interest entities.

Power Contract Monetization VIEs

In March 2005, our NewEnergy business closed a transaction in which we assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, we sell power to the VIEs which, in turn, sell that power to an electric distribution utility through 2013. In connection with this transaction, a third party acquired the equity of the VIEs and we loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to us in lieu of repaying the loan. In this event, we would have the right to seek recovery of our losses from the electric distribution utility.

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5 Intangible Assets

Goodwill

Goodwill is the excess of the cost of an acquisition over the fair value of the net assets acquired. As of December 31, 2010 and 2009, our goodwill balance was primarily related to our retail energy reporting unit within our NewEnergy business segment. Goodwill is not amortized; rather, it is evaluated for impairment at least annually.

The changes in the gross amount of goodwill and the accumulated impairment losses for the years ended December 31, 2010 and 2009 are as follows:

At December 31,	**2010**	2009
	(In millions)	
Balance as of January 1,		
Gross goodwill	**$ 292.0**	$ 271.1
Accumulated impairment losses	**(266.5)**	(266.5)
Net goodwill	**25.5**	4.6
Goodwill acquired (1)	**51.5**	18.6
Impairment losses		
Other purchase price adjustments		2.3
Balance as of December 31,		
Gross goodwill	**343.5**	292.0
Accumulated impairment losses	**(266.5)**	(266.5)
Net goodwill	**$ 77.0**	$ 25.5

(1)
We discuss the goodwill acquired in 2010 in more detail in Note 15.

For tax purposes, $169.4 million of our gross goodwill balance at December 31, 2010 is deductible.

Intangible Assets Subject to Amortization

Intangible assets with finite lives are subject to amortization over their estimated useful lives. The primary assets included in this category are as follows:

At December 31,	**2010**			**2009**		
	Gross Carrying Amount	**Accumulated Amortization**	**Net Asset**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net Asset**
			(In millions)			
Software	**$ 596.8**	**$ (397.1)**	**$ 199.7**	$ 580.5	$ (347.3)	$ 233.2
Permits and licenses	**2.7**	**(1.0)**	**1.7**	2.2	(0.8)	1.4
Other	**22.3**	**(8.2)**	**14.1**	29.0	(13.9)	15.1
Total	**$ 621.8**	**$ (406.3)**	**$ 215.5**	$ 611.7	$ (362.0)	$ 249.7

BGE had intangible assets with a gross carrying amount of $250.2 million and accumulated amortization of $171.4 million at December 31, 2010 and $242.5 million and accumulated amortization of $148.8 million at December 31, 2009 that are included in the table above. Substantially all of BGE's intangible assets relate to software.

We recognized amortization expense related to our intangible assets as follows:

Year Ended December 31,	**2010**	**2009**	**2008**
		(In millions)	
Nonregulated businesses	**$ 64.8**	$ 74.2	$ 66.8
BGE	**25.8**	23.6	20.1
Total Constellation Energy	**$ 90.6**	$ 97.8	$ 86.9

The following is our, and BGE's, estimated amortization expense related to our intangible assets for 2011 through 2015 for the intangible assets included in our, and BGE's, Consolidated Balance Sheets at December 31, 2010:

Year Ended December 31,	**2011**	**2012**	**2013**	**2014**	**2015**
			(In millions)		
Estimated amortization expense Nonregulated businesses	$ 58.5	$ 37.4	$ 19.5	$ 8.8	$ 3.9
Estimated amortization expense BGE	23.7	17.2	13.2	8.6	6.7
Total estimated amortization expense Constellation Energy	$ 82.2	$ 54.6	$ 32.7	$ 17.4	$ 10.6

Unamortized Energy Contracts

As discussed in *Note 1*, unamortized energy contract assets and liabilities represent the remaining unamortized balance of nonderivative energy contracts acquired, certain contracts which no longer qualify as derivatives due to the absence of a liquid market, or derivatives designated as normal purchases and normal sales, which we previously recorded as derivative assets and liabilities. Unamortized energy contract assets also include the power purchase agreement entered into with CENG with an initial fair value of approximately $0.8 billion. See *Note 16* for more details on this power purchase agreement.

We present separately in our Consolidated Balance Sheets the net unamortized energy contract assets and liabilities for these contracts. The table below presents the gross and net carrying amount and accumulated amortization of the net liability that we have recorded in our Consolidated Balance Sheets:

At December 31		**2010**			**2009**	
	Carrying Amount	**Accumul-ated Amortiz-ation**	**Net Asset**	**Carrying Amount**	**Accumul-ated Amortiz-ation**	**Net Liability**
			(In millions)			
Unamortized energy contracts, net	**$ (1,360.9)**	**$ 1,473.8**	**$ 112.9**	$ (1,587.1)	$ 1,584.5	$ (2.6)

We recognized amortization expense of $106.8 million, $353.1 million, and $390.4 million related to these energy contract assets for the years ended December 31, 2010, 2009, and 2008 for our nonregulated businesses.

The table below presents the estimated amortization for these assets and liabilities over the next five-years:

Year Ended December 31,	**2011**	**2012**	**2013**	**2014**	**2015**
			(In millions)		

Estimated amortization	$ 414.1	$ (49.2)	$ (71.8)	$ (71.3)	$ (68.8)

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6 Regulatory Assets (net)

As discussed in *Note 1*, the Maryland PSC and the FERC provide the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC or FERC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain regulated expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (Loss) (using amortization) when we include them in the rates we charge our customers.

We summarize regulatory assets and liabilities in the following table, and we discuss each of them separately below.

At December 31,	**2010**	2009
	(In millions)	
Deferred fuel costs		
Rate stabilization deferral	**$ 415.6**	$ 477.5
Other	**8.8**	14.3
Electric generation-related regulatory asset	**86.9**	102.5
Net cost of removal	**(210.5)**	(210.1)
Income taxes recoverable through future rates (net)	**68.3**	67.6
Deferred Smart Energy Savers Program[SM] costs	**64.3**	10.8
Deferred Advanced Meter Infrastructure costs	**12.2**	11.3
Deferred postretirement and postemployment benefit costs	**8.4**	9.6
Deferred environmental costs	**5.6**	6.5
Workforce reduction costs	**1.3**	1.5
Other (net)	**(8.1)**	(4.6)
Total regulatory assets (net)	**452.8**	486.9
Less: Current portion of regulatory assets (net)	**78.7**	72.5
Long-term portion of regulatory assets (net)	**$ 374.1**	$ 414.4

Deferred Fuel Costs

Rate Stabilization Deferral

In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006 to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the Maryland PSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306.4 million of electricity purchased for resale expenses and certain applicable carrying charges as a regulatory asset related to the rate stabilization plans. During 2010 and 2009, BGE recovered $61.8 million and $51.4 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007. Customers who participated in the deferral from June 1, 2007 to December 31, 2007 repaid the deferred charges without interest over a 21-month period which began in April 2008 and ended in December 2009.

Other

As described in *Note 1*, deferred fuel costs are the difference between our actual costs of purchased energy and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from our customers.

We exclude other deferred fuel costs from rate base because their existence is relatively short-lived. These costs are recovered in the following year through our fuel rates.

Electric Generation-Related Regulatory Asset

As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities. BGE established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

A portion of this regulatory asset represents income taxes recoverable through future rates that do not earn a regulated rate of return. These amounts were $53.3 million as of December 31, 2010 and $62.8 million as of December 31, 2009. We will continue to amortize this amount through 2017.

Net Cost of Removal

As discussed in *Note 1*, we use the group depreciation method for the regulated business. This method is currently an acceptable method of accounting under accounting principles generally accepted in the United States of America and has been widely used in the energy, transportation, and telecommunication industries.

Historically, under the group depreciation method, the anticipated costs of removing assets upon retirement were provided for over the life of those assets as a component of depreciation expense. However, effective January 1, 2003, the recognition of expected net future costs of removal is shown as a component of depreciation expense or accumulated depreciation.

BGE is required by the Maryland PSC to use the group depreciation method, including cost of removal, under regulatory accounting. For ratemaking purposes, net cost of removal is a

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component of depreciation expense and the related accumulated depreciation balance is included as a net reduction to BGE's rate base investment. For financial reporting purposes, BGE continues to accrue for the future cost of removal for its regulated gas and electric assets by increasing a regulatory liability. This liability is relieved when actual removal costs are incurred.

Income Taxes Recoverable Through Future Rates (net)

As described in *Note 1*, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

Deferred Smart Energy Savers ProgramSM Costs

Deferred Smart Energy Savers Program^{SM} costs are the costs incurred to implement demand response and conservation programs. These programs are designed to help BGE manage peak demand, improve system reliability, reduce customer consumption, and improve service to customers by giving customers greater control over their energy use. Actual costs incurred in the demand response program, which began in January 2008, are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the Maryland PSC. Actual costs incurred in the conservation program, which began in February 2009, are being amortized as incurred pursuant to an order by the Maryland PSC.

Deferred Advanced Meter Infrastructure Costs

Between 2007 and 2009, the Maryland PSC approved and BGE conducted a series of successful smart grid pilot programs for a total cost of $11.3 million, which, pursuant to a Maryland PSC order, was deferred in a regulatory asset, without earning a regulatory rate of return. In August 2010, the Maryland PSC approved a comprehensive smart grid initiative for BGE which included the planned installation of 2 million residential and commercial electric and gas smart meters. As part of the Maryland PSC's August 2010 order, BGE has been authorized to establish a separate regulatory asset for incremental costs incurred to implement the initiative, net depreciation and amortization associated with the meters, plus an appropriate return on these costs. Additionally, the Maryland PSC order requires that BGE prove the cost effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown.

Deferred Postretirement and Postemployment Benefit Costs

We record a regulatory asset for the deferred postretirement and postemployment benefit costs in excess of the costs we included in the rates we charged our customers through 1997. We began amortizing these costs over a 15-year period in 1998.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in *Note 12*. We amortized $21.6 million of these costs (the amount we had incurred through October 1995) and are amortizing $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with the Maryland PSC's orders. We applied for and received rate relief for an additional $5.4 million of clean-up costs incurred during the period from July 2000 through November 2005. These costs are being amortized over a 10-year period that began in January 2006.

Workforce Reduction Costs

The portion of the costs associated with our 2008 workforce reduction program that relate to BGE's gas business were deferred in 2009 as a regulatory asset in accordance with the Maryland PSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009.

Other (Net)

Other regulatory assets are comprised of a variety of current assets and liabilities that do not earn a regulatory rate of return due to their short-term nature.

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7 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. BGE employees participate in the benefit plans that we offer. We describe each of our plans separately below. Nine Mile Point, owned by CENG, offers its own pension, postretirement, other postemployment, and employee savings plan benefits to its employees. In connection with the deconsolidation of CENG as a result of the investment in CENG by EDF on November 6, 2009, the Nine Mile Point plan is no longer included in our consolidated results. In addition, benefit plan assets and obligations relating to CENG employees that previously participated in our plans were transferred into new CENG plans that are no longer included in our consolidated results. Therefore, the tables below include the benefits for the CENG plans, including Nine Mile Point, through November 6, 2009.

We use a December 31 measurement date for our pension, postretirement, other postemployment, and employee savings plans. The following table summarizes our defined benefit liabilities and their classification in our Consolidated Balance Sheets:

At December 31,	**2010**	2009
	(In millions)	
Pension benefits	**$ 218.0**	$ 411.7
Postretirement benefits	**334.9**	322.3
Postemployment benefits	**55.0**	50.6
Total defined benefit obligations	**607.9**	784.6
Less: Amount recorded in other current liabilities	**33.2**	40.7
Total noncurrent defined benefit obligations	**$ 574.7**	$ 743.9

Pension Benefits

We sponsor several defined benefit pension plans for our employees. These include basic qualified plans that most employees participate in and several non-qualified plans that are available only to certain employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

Sometimes we amend the plans retroactively. These retroactive plan amendments require us to recalculate benefits related to participants' past service. We amortize the change in the benefit costs from these plan amendments on a straight-line basis over the average remaining service period of active employees.

We fund the qualified plans by contributing at least the minimum amount required under IRS regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method.

Postretirement Benefits

We sponsor defined benefit postretirement health care and life insurance plans that cover the majority of our employees. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels or final base pay. We do not fund these plans. For nearly all of the health care plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs.

Effective in 2002, we amended our postretirement medical plans for all subsidiaries other than Nine Mile Point. Our contributions for retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 are capped at the 2002 level. We also amended our plans to increase the Medicare eligible retirees' share of medical costs.

In 2003, the President signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act). This legislation provides a prescription drug benefit for Medicare beneficiaries, a benefit that we provide to our Medicare eligible retirees. Our actuaries concluded that prescription drug benefits available under our postretirement medical plan are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Act. This subsidy reduced our 2010 Accumulated Postretirement Benefit Obligation by $30.9 million and our 2010 postretirement medical payments by $2.2 million.

Liability Adjustments

At December 31, 2010 and 2009, our pension obligations and the fair value of our plan assets for our qualified and our nonqualified pension plans were as follows:

At December 31, 2010	***Qualified Plan***	***Non-Qualified Plans***	***Total***
		(In millions)	
Accumulated benefit obligation	**$ 1,405.2**	**$ 87.8**	**$ 1,493.0**
Fair value of assets	**1,408.1**		**1,408.1**
Net (asset) unfunded obligation	**$ (2.9)**	**$ 87.8**	**$ 84.9**

At December 31, 2009	**Qualified Plan**	**Non-Qualified Plans**	**Total**
Accumulated benefit obligation	$ 1,277.5	$ 84.1	$ 1,361.6
Fair value of assets	1,058.1		1,058.1
Net unfunded obligation	$ 219.4	$ 84.1	$ 303.5

We are required to reflect the funded status of our pension plans in terms of the projected benefit obligation, which is higher than the accumulated benefit obligation because it includes the impact of expected future compensation increases on the pension obligation. We reflect the funded status of our postretirement benefits in terms of the accumulated postretirement benefit obligation.

The following table summarizes the impacts of funded status adjustments recorded during 2010 and 2009:

	Pension Liability	Postretirement Benefit Liability	Accumulated Other Comprehensive Income (Loss) Pre-tax	Accumulated Other Comprehensive Income (Loss) After-tax
	(In millions)			
December 31, 2010	**$ 73.7**	**$ 10.9**	**$ (84.6)**	**$ (54.6)**
December 31, 2009	$ (49.3)	$ 1.0	$ 48.3	$ 25.4
November 6, 2009 (1)	$ (211.7)	$ (20.9)	$ 232.6	$ 138.0

(1) *We performed a remeasurement of our pension and postretirement obligations at November 6, 2009 in connection with the separation of a portion of those plans upon the deconsolidation of CENG.*

Obligations and Assets

We show the change in the benefit obligations and plan assets of the pension and postretirement benefit plans in the following tables. Postretirement benefit plan amounts are presented net of expected reimbursements under Medicare Part D.

	Pension Benefits 2010	Pension Benefits 2009	Postretirement Benefits 2010	Postretirement Benefits 2009
	(In millions)			
Change in benefit obligation (1)				
Benefit obligation at January 1	**$ 1,469.8**	$ 1,804.3	**$ 322.3**	$ 415.4
Service cost	**37.9**	50.8	**2.4**	6.3
Interest cost	**84.7**	101.1	**17.7**	22.6
Plan amendments		2.4	**(3.3)**	
Plan participants' contributions			**10.5**	10.2
Actuarial loss (gain)	**124.0**	55.8	**14.2**	1.0
Separation of CENG plans	**(3.0)**	(410.5)		(98.6)
Settlements	**(5.2)**	(19.0)		
Special termination benefits	**0.6**	0.1	**0.1**	
Benefits paid (2)(3)	**(82.7)**	(115.2)	**(29.0)**	(34.6)
Benefit obligation at December 31	**$ 1,626.1**	$ 1,469.8	**$ 334.9**	$ 322.3

(1) *Amounts reflect projected benefit obligation for pension benefits and accumulated postretirement benefit obligation for postretirement benefits.*

(2) *Pension benefits paid include annuity payments and lump-sum distributions.*

(3) *Postretirement benefits paid are net of Medicare Part D reimbursements.*

	Pension Benefits		Postretirement Benefits	
	2010	**2009**	**2010**	**2009**
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$ 1,058.1**	$ 867.6	**$**	$
Actual return on plan assets	**148.8**	217.6		
Employer contribution (1)	**289.1**	341.5	**18.5**	24.4
Plan participants' contributions			**10.5**	10.2
Separation of CENG Plan		(234.4)		
Settlements	**(5.2)**	(19.0)		
Benefits paid (2)(3)	**(82.7)**	(115.2)	**(29.0)**	(34.6)
Fair value of plan assets at December 31	**$ 1,408.1**	$ 1,058.1	**$**	$

(1) *Includes benefit payments for unfunded plans.*

(2) *Pension benefits paid include annuity payments and lump-sum distributions.*

(3) *Postretirement benefits paid are net of Medicare Part D reimbursements.*

Net Periodic Benefit Cost and Amounts Recognized in Other Comprehensive Income

We show the components of net periodic pension benefit cost in the following table:

Year Ended December 31,	**2010**	**2009**	**2008**
		(In millions)	
Components of net periodic pension benefit cost			
Service cost	**$ 37.9**	$ 50.8	$ 55.4
Interest cost	**84.7**	101.1	100.2
Expected return on plan assets	**(101.8)**	(118.9)	(111.3)
Amortization of unrecognized prior service cost	**3.9**	10.9	10.9
Recognized net actuarial loss	**34.4**	38.3	24.7
Amount capitalized as construction cost	**(10.2)**	(10.2)	(10.2)
Net periodic pension benefit cost (1)	**$ 48.9**	$ 72.0	$ 69.7

(1) *Net periodic pension benefit cost excludes settlement charges of $1.5 million and termination benefits of $0.6 million in 2010, settlement charge of $9.0 million and termination benefits of $0.1 million in 2009, and termination benefits of $2.2 million in 2008. BGE's portion of our net periodic pension benefit costs, excluding amount capitalized, was $30.9 million in 2010, $27.9 million in 2009, and $25.5 million in 2008. The vast majority of our retirees were BGE employees.*

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We show the components of net periodic postretirement benefit cost in the following table:

Year Ended December 31,	2010	2009	2008
		(In millions)	
Components of net periodic postretirement benefit cost			
Service cost	**$ 2.4**	$ 6.3	$ 6.1
Interest cost	**17.7**	22.6	24.0
Amortization of transition obligation	**2.1**	2.1	2.1
Recognized net actuarial loss	**0.4**	2.2	2.0
Amortization of unrecognized prior service cost	**(2.6)**	(3.4)	(3.5)
Amount capitalized as construction cost	**(5.4)**	(6.3)	(7.6)
Net periodic postretirement benefit cost (1)	**$ 14.6**	$ 23.5	$ 23.1

(1)
Net periodic postretirement benefit cost excludes termination benefits of $0.1 million in 2010 and $0.8 million in 2008. BGE's portion of our net periodic postretirement benefit cost, excluding amounts capitalized, was $17.2 million in 2010, $18.7 million in 2009, and $20.4 million in 2008.

In determining net periodic pension benefit cost, we apply our expected return on plan assets to a market-related value of plan assets that recognizes asset gains and losses ratably over a five-year period.

The following is a summary of amounts we have recorded in "Accumulated other comprehensive loss" and of expected amortization of those amounts over the next twelve months:

	Pension Benefits		Postretirement Benefits		Expected Amortiz-ation Next
	2010	2009	2010	2009	12 Months
			(In millions)		
Unrecognized actuarial loss	**$ 741.4**	$ 702.2	**$ 65.3**	$ 51.5	$ 49.5
Unrecognized prior service cost	**6.1**	9.9	**(14.0)**	(13.9)	1.1
Unrecognized transition obligation			**3.5**	6.2	1.8
Total	**$ 747.5**	$ 712.1	**$ 54.8**	$ 43.8	$ 52.4

Expected Cash Benefit Payments

The pension and postretirement benefits we expect to pay in each of the next five calendar years and in the aggregate for the subsequent five years are shown in the following table. These estimated benefits are based on the same assumptions used to measure the benefit obligation at December 31, 2010, but include benefits attributable to estimated future employee service.

	Pension Benefits	Postretirement Benefits (1)
2011	$ 105.5	$ 23.0
2012	100.5	23.3
2013	108.1	23.8
2014	111.3	24.4
2015	147.9	24.8
2016-2020	669.3	127.4

(1) *Postretirement benefit payments are net of Medicare Part D reimbursements.*

Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations and periodic cost.

	Pension Benefits		Postretirement Benefits		Assumption Impacts
	2010	**2009**	**2010**	**2009**	**Calculation of**
Discount rate	**5.50%**	6.00%	**5.50%**	6.00%	Benefit Obligation and Periodic Cost
Expected return on plan assets	**8.50**	8.50	**N/A**	N/A	Periodic Cost
Rate of compensation increase	**4.0**	4.0	**4.0**	4.0	Benefit Obligation and Periodic Cost

Our discount rate is based on a bond portfolio analysis of high quality corporate bonds whose maturities match our expected benefit payments. Our 8.50% overall expected long-term rate of return on plan assets reflected our long-term investment strategy in terms of asset mix and expected returns for each asset class at the beginning of 2010. Effective in 2011, we reduced our expected long-term rate of return assumption to 8.00% reflecting our updated investment strategy, asset mix, and expected return for each asset class.

Annual health care inflation rate assumptions also impact the calculation of our postretirement benefit obligation and periodic cost. We assumed the following health care inflation rates to produce average claims by year as shown below:

At December 31,	**2010**	**2009**
Next year	**8.5%**	8.0%
Following year	**7.5%**	7.5%
Ultimate trend rate	**5.0%**	5.0%
Year ultimate trend rate reached	**2017**	2016

A one-percentage point increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $21.6 million as of December 31, 2010 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $1.2 million annually.

A one-percentage point decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $18.8 million

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as of December 31, 2010 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $1.1 million annually.

Qualified Pension Plan Assets

Investment Strategy

We invest our qualified pension plan assets using the following investment objectives:

- ensure availability of funds for payment of plan benefits as they become due,
- provide for a reasonable amount of long-term growth of capital (both principal and income) without excessive volatility,
- produce investment results that meet or exceed the assumed long-term rate of return,
- improve the funded status of the plan over time, and
- reduce future contribution and expense volatility as funded status improves.

To achieve these objectives, Constellation Energy, through a management Investment Committee (the Committee), has adopted an investment strategy that divides its pension investment program into two primary portfolios:

- return seeking assets those assets intended to generate returns in excess of pension liability growth, and
- liability hedging assets those assets intended to have characteristics similar to pension liabilities.

Currently, the Committee allocates 60% of its plan assets to return seeking assets to help reduce existing deficits in the funded status of the plan. As the funded status of our plans improve, the Committee expects to reduce its exposure to return seeking assets and increase its liability hedging assets to reduce its total risk.

Return Seeking Assets

The purpose of return seeking assets is to provide investment returns in excess of the growth of pension liabilities. This category includes a diversified portfolio of public equities, private equity, real estate, hedge funds, high yield bonds and other instruments. These assets are likely to have lower correlations with the pension liabilities and lead to higher funded status risk over shorter periods of time.

Liability Hedging Assets

The purpose of liability hedging assets, such as long duration bonds and interest rate derivatives, is to hedge against interest rate changes. Exposure to liability hedging assets is intended to reduce the volatility of plan funded status, contributions, and pension expense.

Risk Management

The Committee manages plan asset risk using several approaches. First, the assets are invested in two diverse portfolios, each of which contains investments across a spectrum of asset classes. Second, the Committee considers the long-term investment horizon of the plan, which is greater than ten years. The long-term horizon enables the Committee to tolerate the risk of investment losses in the short-term with the expectation of higher returns in the long-term. Third, the Committee employs a thorough due diligence program prior to selecting an investment, and a rigorous ongoing monitoring program once assets are invested. The Committee evaluates risk on an ongoing basis.

Asset Allocation

Plan assets are diversified across various asset classes and securities based on the investment strategy approved by the Committee. This policy allocation is long-term oriented and consistent with the risk tolerance and funded status. The target asset allocation as well as the actual allocations for 2010 and 2009 are provided below.

	Target Allocation		Actual Allocation	
At December 31,	**2010**	**2009**	**2010**	**2009**
Global equity securities	**42%**	48%	**42%**	57%
Fixed income securities	**40**	30	**37**	27
Alternative investments	**12**	15	**8**	7
High yield bonds	**6**	7	**6**	7
Cash and cash equivalents			**7**	2
Derivative instruments				
Total	**100%**	100%	**100%**	100%

The target asset allocation also allows for investments in financial instruments, including asset-backed securities and collateralized mortgage obligations, which are exposed to interest rate and market risk as well as overall market volatility. These instruments are sensitive to changes in economic conditions. Such changes could materially affect the amounts reported.

The actual portfolio was rebalanced in December 2010 in accordance with policy target allocations and an improvement in funded status. The Committee will also rebalance our portfolio periodically when the actual allocations fall outside of the ranges prescribed in the investment policy or as the funded status improves.

Fair Value Hierarchy

We determine the fair value of the plan assets using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. We use unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available. We classify assets within this fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset taken as a whole.

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The following tables set forth by level, within the fair value hierarchy, the investments in the Plans' master trust at fair value as of December 31, 2010 and 2009:

At December 31, 2010	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
		(In millions)		
Global equity securities:				
Marketable equity securities	$ 143.6	$	$	$ 143.6
Common collective trusts		447.5		447.5
Fixed income securities:				
Corporate debt securities		327.9		327.9
Government / agency securities		113.0		113.0
Municipal bonds		54.8		54.8
Guarantee insurance contracts		21.6		21.6
High yield bonds		86.9		86.9
Cash equivalents	93.6			93.6
Derivative instruments		0.9		0.9
Alternative investments			118.3	118.3
Total	$ 237.2	$ 1,052.6	$ 118.3	$ 1,408.1

At December 31, 2009	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
		(In millions)		
Global equity securities	$ 215.4	$ 383.0	$	$ 598.4
Fixed income securities		289.2		289.2
High yield bonds	0.6	75.6		76.2
Cash equivalents	19.9			19.9
Alternative investments			74.4	74.4
Total	$ 235.9	$ 747.8	$ 74.4	$ 1,058.1

The following is a description of the valuation methodologies used for assets measured at fair value:

Global equity securities, which include marketable equity securities and common collective trust securities, are valued at unadjusted quoted market share prices within active markets (Level 1) or based on external price/spread data of comparable securities (Level 2). Common collective trust funds within this category are valued at fair value based on the unit value of the fund which is observable on a less frequent basis (Level 2). Unit values are determined by the bank or financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates.

Fixed income (primarily corporate debt securities, government and agency securities, municipal bonds, and guarantee insurance contracts), high yield bonds, and over-the-counter derivatives are valued based on external price data of comparable securities (Level 2).

Cash equivalents consist of money market funds, which are valued by multiplying unadjusted quoted prices in active markets by the quantity of the assets (Level 1).

Alternative investments primarily consist of hedge funds, real estate funds, and financial limited partnerships (private equity funds). These investments do not have readily determinable fair values because they are not listed on national exchanges or over-the-counter markets. We have valued these alternative investments at their respective net asset value per share (or its equivalent such as partner's capital) which has been calculated by each partnership's general partner in a manner consistent with generally accepted accounting principles in the United States of America for investment companies. Among other requirements, the partnerships must value their underlying investments at fair value. While the net asset value per share provides a reasonable approximation of fair value, the fair values of the alternative investments are estimates and, accordingly, such estimated values may differ from the values that would have been used had a ready market for the investments existed, and the differences could be material.

The following table summarizes the changes in the fair value of the Level 3 assets for the years ended December 31, 2010 and 2009:

	Year Ended December 31, 2010	Year Ended December 31, 2009
	(In millions)	
Balance at beginning of period	**$ 74.4**	$ 96.3
Actual return on plan assets:		
Assets still held at year end	**(32.1)**	(2.5)
Assets sold during the year	**37.0**	6.4
Purchases, sales, and settlements	**22.2**	(10.8)
Transfers into Level 3	**16.8**	
Transfers out of Level 3		
Net transfers into and out of Level 3	**16.8**	(15.0)
Balance at end of year	**$ 118.3**	$ 74.4

Contributions and Benefit Payments

We contributed $279.7 million to our qualified pension plans in 2010. $243.0 million of this contribution was an acceleration of estimated calendar year 2011 and 2012 contributions. Therefore, we do not plan to make contributions to our qualified pension plans in 2011 and 2012. Our non-qualified pension plans and our postretirement benefit programs are not funded. We estimate that we will incur approximately $7 million in pension benefits for our non-qualified pension plans and approximately $23 million for retiree health and life insurance costs net of Medicare Part D during 2011.

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Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to eligible employees determined to be disabled under our Disability Insurance Plan, and
- income replacement payments for employees determined to be disabled before November 1995 (payments for employees determined to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

We recognized expense associated with our other postemployment benefits of $9.9 million in 2010, $5.3 million in 2009, and $1.9 million in 2008. BGE's portion of expense associated with other postemployment benefits was $7.6 million in 2010, $4.4 million in 2009, and $2.2 million in 2008.

We assumed the discount rate for other postemployment benefits to be 4.00% in 2010 and 4.75% in 2009. This assumption impacts the calculation of our other postemployment benefit obligation and periodic cost.

Employee Savings Plan Benefits

We sponsored two defined contribution plans until November 6, 2009, when upon the close of the sale of a 49.99% interest in CENG to EDF, we deconsolidated CENG and the defined contribution plan related to Nine Mile Point was removed from our books. For all remaining eligible employees of Constellation Energy, we continue to sponsor a defined contribution savings plan. The savings plan is a qualified 401(k) plan under the Internal Revenue Code. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Matching contributions to participant accounts are made under these plans. Matching contributions were as follows:

Year Ended December 31,	**2010**	2009	2008
		(In millions)	
Nonregulated businesses	**$ 9.9**	$ 14.8	$ 17.6
BGE	**6.3**	5.7	5.8
Total Constellation Energy	**$ 16.2**	$ 20.5	$ 23.4

8 Credit Facilities and Short-Term Borrowings

Our short-term borrowings may include bank loans, commercial paper, and bank lines of credit. Short-term borrowings mature within one year from the date of issuance. We pay commitment fees to banks for providing us lines of credit. When we borrow under the lines of credit, we pay market interest rates. We enter into these facilities to ensure adequate liquidity to support our operations.

Constellation Energy

Our liquidity requirements are funded with credit facilities and cash. We fund our short-term working capital needs with existing cash and with our credit facilities, which support direct cash borrowings and the issuance of commercial paper, if available. We also use our credit facilities to support the issuance of letters of credit, primarily for our NewEnergy business.

Constellation Energy had bank lines of credit under committed credit facilities totaling $4.2 billion at December 31, 2010 for short-term financial needs as follows:

Type of Credit Facility	Amount (In billions)		Expiration Date	Capacity Type
Syndicated Revolver	$	2.50	October 2013	Letters of credit and cash
Commodity-linked		0.50	August 2014	Letter of credit and cash
Bilateral		0.55	September 2014	Letters of credit
Bilateral		0.25	December 2014	Letters of credit and cash
Bilateral		0.25	June 2014	Letters of credit and cash
Bilateral		0.15	September 2013	Letters of credit
Total	$	4.20		

At December 31, 2010, we had approximately $1.6 billion in letters of credit issued, including $0.4 billion in letters of credit issued under the commodities-linked credit facility discussed below, and no commercial paper outstanding under these facilities.

The commodity-linked credit facility currently allows for the issuance of letters of credit and, as modified in 2010, for cash borrowings, up to a maximum capacity of $0.5 billion. This commodity-linked facility is designed to help manage our contingent collateral requirements associated with the hedging of our NewEnergy business because its capacity increases up to the maximum capacity as natural gas price levels decrease compared to a reference price that is adjusted periodically.

At December 31, 2010, Constellation Energy had $32.4 million of short-term notes outstanding with a weighted-average effective interest rate of 6.56%.

BGE

BGE has a $600.0 million revolving credit facility expiring in December 2011. BGE can borrow directly from the banks, use the facility to allow commercial paper to be issued, if available, or issue letters of credit. At December 31, 2010, BGE had no commercial paper outstanding. There were immaterial letters of credit outstanding at December 31, 2010.

Net Available Liquidity

The following table provides a summary of our net available liquidity at December 31, 2010:

At December 31, 2010	**Constellation Energy (excluding BGE)**	**BGE**

		(In billions)		
Credit facilities (1)	$	3.7	$	0.6
Less: Letters of credit issued (1)		(1.2)		
Less: Cash drawn on credit facilities				
Undrawn facilities		2.5		0.6
Less: Commercial paper outstanding				
Net available facilities		2.5		0.6
Add: Cash and cash equivalents (2)		2.0		
Less: Reserved cash (3)		(1.2)		
Net available liquidity	$	3.3	$	0.6

(1)

Excludes $0.5 billion commodity-linked credit facility due to its contingent nature and $0.4 billion in letters of credit posted against it.

(2)

BGE's cash balance at December 31, 2010 was $50.0 million.

(3)

Represents management's expectation at December 31, 2010 of payments for the January 2011 acquisition of the Boston Generating plants ($1.0 billion) and the January 2011 retirement of the 2012 Notes ($0.2 billion).

Credit Facility Compliance and Covenants

The credit facilities of Constellation Energy and BGE contain a material adverse change representation but draws on the facilities are not conditioned upon Constellation Energy and BGE making this representation at the time of the draw. However, to the extent a material adverse change has occurred and prevents Constellation Energy or BGE from making other representations that are required at the time of the draw, the draw would be prohibited.

Certain credit facilities of Constellation Energy contain a provision requiring Constellation Energy to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2010, the debt to capitalization ratio as defined in the credit agreements was 36%.

The credit agreement of BGE contains a provision requiring BGE to maintain a ratio of debt to capitalization equal to or less than 65%. At December 31, 2010, the debt to capitalization ratio for BGE as defined in this credit agreement was 43%.

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Decreases in Constellation Energy's or BGE's credit ratings would not trigger an early payment on any of our, or BGE's, credit facilities. However, the impact of a credit ratings downgrade on our financial ratios associated with our credit facility covenants would depend on our financial condition at the time of such a downgrade and on the source of funds used to satisfy the incremental collateral obligation resulting from a credit ratings downgrade. For example, if we were to use existing cash balances to fund the cash portion of any additional collateral obligations resulting from a credit ratings downgrade, we would not expect a material impact on our financial ratios. However, if we were to issue long-term debt or use our credit facilities to fund any additional collateral obligations, our financial ratios could be materially affected. Failure by Constellation Energy, or BGE, to comply with these covenants could result in the acceleration of the maturity of the borrowings outstanding and preclude us from issuing letters of credit under these facilities.

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9 Capitalization

We detail in the table below our total capitalization, which includes long-term debt, common stock, noncontrolling interests, and preference stock, as of December 31, 2010 and 2009.

At December 31,	**2010**	2009
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
8.625% Series A Junior Subordinated Debentures, due June 15, 2063	**$ 450.0**	$ 450.0
7.00% Fixed-Rate Notes, due April 1, 2012	**213.5**	700.0
4.55% Fixed-Rate Notes, due June 15, 2015	**550.0**	550.0
5.15% Fixed-Rate Notes, due December 1, 2020	**550.0**	
7.60% Fixed-Rate Notes, due April 1, 2032	**700.0**	700.0
Fair Value of Interest Rate Swaps	**36.2**	38.6
Total long-term debt of Constellation Energy	**2,499.7**	2,438.6
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
4.10% Pollution control loan, due July 1, 2014	**20.0**	20.0
Tax-exempt variable rate notes, due April 1, 2024	**75.0**	75.0
Tax-exempt variable rate notes, due December 1, 2025		47.0
Tax-exempt variable rate notes, due December 1, 2037		65.0
5.00% Mortgage note, due June 15, 2010		0.4
7.3% Fixed Rate Note, due June 1, 2012	**1.7**	1.7
Asset-based lending agreement due July 16, 2012	**18.0**	27.1
Total long-term debt of nonregulated businesses	**114.7**	236.2
Other long-term debt of BGE		
6.125% Notes, due July 1, 2013	**400.0**	400.0
5.90% Notes, due October 1, 2016	**300.0**	300.0
5.20% Notes, due June 15, 2033	**200.0**	200.0
6.35% Notes, due October 1, 2036	**400.0**	400.0
Medium-term notes, Series E	**131.5**	131.5
Total other long-term debt of BGE	**1,431.5**	1,431.5
6.20% deferrable interest subordinated debentures due October 15, 2043 to BGE wholly owned BGE Capital Trust II relating to trust preferred securities	**257.7**	257.7
Rate stabilization bonds	**454.4**	510.9
Unamortized discount and premium	**(3.9)**	(4.0)
Current portion of long-term debt	**(305.3)**	(56.9)
Total long-term debt	**$ 4,448.8**	$ 4,814.0

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At December 31,	2010	2009
	(In millions)	
Equity:		
Noncontrolling Interests	**$ 88.8**	$ 75.3
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized 7.125%, 1993 Series, 400,000 shares outstanding, callable at $101.07 per share until June 30, 2011, and at lesser amounts thereafter	**40.0**	40.0
6.97%, 1993 Series, 500,000 shares outstanding, callable at $101.05 per share until September 30, 2011, and at lesser amounts thereafter	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, callable at $101.01 per share until December 31, 2011, and at lesser amounts thereafter	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, callable at $101.75 per share until September 30, 2011, and at lesser amounts thereafter	**60.0**	60.0
Total BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 600,000,000 shares authorized; 199,788,658 and 200,985,414 shares issued and outstanding at December 31, 2010 and 2009, respectively. (At December 31, 2010, 12,818,160 shares were reserved for the long-term incentive plans, 8,788,849 shares were reserved for the shareholder investment plan, and 1,884,258 shares were reserved for the employee savings plan.)	**3,231.7**	3,229.6
Retained earnings	**5,270.8**	6,461.0
Accumulated other comprehensive loss	**(673.3)**	(993.5)
Total common shareholders' equity	**7,829.2**	8,697.1
Total Equity	**8,108.0**	8,962.4
Total Capitalization	**$ 12,556.8**	$ 13,776.4

BGE Common Shareholder Equity

At December 31,	2010	2009
	(In millions)	
Common Stock	**$ 1,293.1**	$ 1,293.1
Retained Earnings	**779.5**	645.1
Accumulated other comprehensive income	**0.6**	0.6
Total BGE common shareholder equity	**$ 2,073.2**	$ 1,938.8

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

Long-term Debt

Long-term debt matures in one year or more from the date of issuance. The long-term debt of Constellation Energy and BGE do not contain material adverse change clauses. We detail our long-term debt in the table above.

Constellation Energy

5.15% Notes due December 1, 2020

In December 2010, we issued $550 million of 5.15% Notes due December 1, 2020. Interest is payable semi-annually on June 1 and December 1, beginning June 1, 2011. At any time prior to September 1, 2020, we may redeem some or all of the notes at a price equal to the greater of 100% of the principal amount of the notes outstanding to be redeemed and the sum of the present values of the remaining scheduled payments of principal and interest on the notes being redeemed, discounted to the redemption date on a semi-annual basis at the Treasury rate plus 30 basis points, plus accrued interest. After September 1, 2020, we may redeem some or all of the notes at a price equal to 100% of the principal amount of the notes outstanding to be redeemed plus accrued interest on the principal amount being redeemed to the redemption date.

Additionally, in December 2010, we issued a notice to redeem $213.5 million of our 7.00% Notes, which represented the remaining outstanding 7.00% Notes due April 1, 2012. As such, we classified these notes as "Current portion of long-term debt" in our Consolidated Balance Sheets. In January 2011, we redeemed these notes with part of the proceeds from the issuance of the $550 million 5.15% Notes, terminated the associated interest rate swaps, and recognized a pre-tax loss of approximately $5 million on this transaction.

During February 2011, we entered into interest rate swaps qualifying as fair value hedges related to $350 million of our fixed rate debt maturing in 2015. We also entered into $150 million of interest rate swaps related to our fixed rate debt maturing in 2020 that do not qualify as fair value hedges, and will be marked to market through earnings. These swaps effectively converted $500 million notional amount of fixed rate debt to floating rate for the term of the swaps.

We discuss our interest rate swaps in *Note 13*.

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Upstream Gas Property Asset-Based Lending Agreement

In July 2009, we entered into a three year asset-based lending agreement associated with certain upstream gas properties that we own. At December 31, 2010, the borrowing base committed under the facility was $100 million, of which $18.0 million has been utilized and reflected in "Long-term debt" in our Consolidated Balance Sheets. The size of the facility may be increased up to $200 million with additional commitments by the lenders. Any debt issued under this facility is secured by the upstream gas properties, and the lenders do not have recourse against Constellation Energy in the event of a default. Interest is payable quarterly in March, June, September, and December.

This asset-based lending agreement contains a provision that requires certain of our entities that own our upstream gas properties to maintain a current ratio of one-to-one. As of December 31, 2010, these entities were in compliance with this provision.

Voluntary Debt Retirements

As part of our voluntary commitment to reduce our debt by $1 billion with funds received from the EDF transaction, we retired the following debt completing this commitment.

7.00% Notes due April 1, 2012

In February 2010, we retired an aggregate principal amount of $486.5 million of our 7.00% Notes due April 1, 2012 pursuant to a cash tender offer, at a premium of approximately 11%. We recorded a loss on this transaction of $51.6 million within "Interest expense" on our Consolidated Statements of Income (Loss).

Tax-Exempt Notes

During 2009, we retired approximately $150 million of variable rate tax exempt notes prior to maturity. In March, 2010, we repurchased our outstanding $47 million and $65 million variable rate tax-exempt notes. Since these notes are variable rate instruments, there was no gain or loss recorded upon repurchase.

Zero Coupon Senior Notes

In November 2009, we redeemed an aggregate principal amount of $267.6 million for the Zero Coupon Senior Notes early and recognized a pre-tax loss on redemption of $16.0 million. We recorded the loss within "Interest expense" in the Consolidated Statements of Income (Loss).

BGE

Secured Indenture

BGE entered into a secured indenture in July 2009. The secured indenture creates a first priority lien on substantially all of BGE's electric utility distribution equipment and fixtures and on BGE's franchises, permits, and licenses that are transferable and necessary for the operation of the equipment and fixtures. As of December 31, 2010, BGE has not issued any secured bonds under this indenture.

BGE's Rate Stabilization Bonds

In June 2007, BondCo, a subsidiary of BGE, issued an aggregate principal amount of $623.2 million of rate stabilization bonds to recover deferred power purchase costs. We discuss BondCo in more detail in *Note 4*. Below are the details of the rate stabilization bonds at December 31, 2010:

Principal	**Interest Rate**	**Scheduled Maturity Date**
$115.2	5.47%	October 2012
220.0	5.72	April 2016
119.2	5.82	April 2017

The bonds are secured primarily by a usage-based, non-bypassable charge payable by all of BGE's residential electric customers over a ten year period. The charges will be adjusted semi-annually to ensure that the aggregate charges collected are sufficient to pay principal and interest on the bonds, as well as certain on-going costs of administering and servicing the bonds. BondCo cannot use the charges collected to satisfy any other obligations. BondCo's assets are not assets of any affiliate and are not available to pay creditors of any affiliate of BondCo. If BondCo is unable to make principal and interest payments on the bonds, neither Constellation Energy, nor BGE, are required to make the payments on behalf of BondCo.

BGE's Other Long-Term Debt

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our Generation business related to the transferred generating assets. At December 31, 2010, BGE remains contingently liable for the $20 million outstanding balance of this debt.

BGE's fixed-rate medium-term note, series E, outstanding at December 31, 2010 has a weighted average interest rate of 6.73%, maturing between 2011 and 2012.

BGE Deferrable Interest Subordinated Debentures

On November 21, 2003, BGE Capital Trust II (BGE Trust II), a Delaware statutory trust established by BGE, issued 10,000,000 Trust Preferred Securities for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 6.20%.

BGE Trust II used the net proceeds from the issuance of common securities to BGE and the Trust Preferred Securities to purchase a series of 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 (6.20% debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the Trust Preferred Securities. BGE Trust II must redeem the Trust Preferred Securities at $25 per preferred security plus accrued but unpaid distributions when the 6.20% debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the 6.20% debentures at any time on or after November 21, 2008 or at any time when certain tax or other events occur.

BGE Trust II will use the interest paid on the 6.20% debentures to make distributions on the Trust Preferred

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Securities. The 6.20% debentures are the only assets of BGE Trust II.

BGE fully and unconditionally guarantees the Trust Preferred Securities based on its various obligations relating to the trust agreement, indentures, 6.20% debentures, and the preferred security guarantee agreement.

For the payment of dividends and in the event of liquidation of BGE, the 6.20% debentures are ranked prior to preference stock and common stock.

Maturities of Long-Term Debt

As of December 31, 2010, our long-term borrowings mature on the following schedule:

Year	Constellation Energy	Nonregulated Businesses	BGE	Total
		(In millions)		
2011	$ 223.6	$	$ 81.7	$ 305.3
2012		19.7	172.5	192.2
2013			466.6	466.6
2014		20.0	70.4	90.4
2015	576.2		74.5	650.7
Thereafter	1,699.9	75.0	1,277.9	3,052.8
Total	$ 2,499.7	$ 114.7	$ 2,143.6	$ 4,758.0

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt outstanding were:

At December 31,	**2010**	**2009**
Nonregulated Businesses (including Constellation Energy)		
Loans under credit agreements	**4.50%**	4.50%
Tax-exempt debt	**0.30%**	1.22%
Fixed-rate debt converted to floating *	**1.23%**	2.30%

* *As discussed in Note 13, as of December 31, 2010, we have interest rate swaps relating to $400.0 million of our fixed-rate debt. In January 2011, we terminated $200.0 million of these swaps.*

Preference Stock

Each series of BGE preference stock has no voting power, except for the following:

- the preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and

- whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.