GenOn Energy, Inc.
Form 10-K
March 01, 2011

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

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 1-16455

GenOn Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0655566**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
1000 Main Street, Houston, Texas	**77002**
(Address of Principal Executive Offices)	*(Zip Code)*

(832) 357-3000
(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.001 per share, and associated rights to purchase Series A Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act. Yes þ   No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o   No þ

Indicate by check mark whether the registrant (1) has 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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ   No o

Indicate by check mark whether the registrant 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ   No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant s 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 the registrant 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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o Yes þ No

Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $1,334,952,151 on June 30, 2010 (based on $3.79 per share, the closing price in the daily composite list for transactions on the New York Stock Exchange that day). Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $2,918,449,213 on December 31, 2010 (based on $3.81 per share, the closing price in the daily composite list for transactions on the New York Stock Exchange that day).

As of February 18, 2011, there were 770,915,236 shares of the registrant s Common Stock, $0.001 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s proxy statement for the 2011 Annual Meeting of Stockholders are incorporated by reference in Part III of this Form 10-K to the extent described herein.

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GLOSSARY OF CERTAIN DEFINED TERMS

AB 32	California s Global Warming Solutions Act.
ancillary services	Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services include regulation service, reserves and voltage support.
Bankruptcy Court	United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division.
baseload generating units	Units designed to satisfy minimum baseload requirements of the system and produce electricity at an essentially constant rate and run continuously.
CAIR	Clean Air Interstate Rule.
CAISO	California Independent System Operator.
CAMR	Clean Air Mercury Rule.
capacity	Energy that could have been generated at continuous full-power operation during the period.
CARB	California Air Resources Board.
CenterPoint	CenterPoint Energy, Inc. and its subsidiaries, on and after August 31, 2002, and Reliant Energy, Incorporated and its subsidiaries, prior to August 31, 2002.
CERCLA	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CFTC	Commodity Futures Trading Commission.
Clean Air Act	Federal Clean Air Act.
Clean Water Act	Federal Water Pollution Control Act.
Climate Protection Act	Massachusetts Global Warming Solutions Act.
CO_2	Carbon dioxide.
Company	GenOn Energy, Inc. (formerly known as RRI Energy, Inc.) and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Merger.

D.C. Circuit	The United States Court of Appeals for the District of Columbia Circuit.
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act.
EBITDA	Earnings before interest, taxes, depreciation and amortization.
EPA	United States Environmental Protection Agency.
EPC	Engineering, procurement and construction.
EPS	Earnings per share.
Exchange Act	Securities Exchange Act of 1934, as amended.
Exchange Ratio	Right of Mirant Corporation stockholders to receive 2.835 shares of common stock of RRI Energy, Inc. in the Merger.
FASB	Financial Accounting Standards Board.

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GLOSSARY OF CERTAIN DEFINED TERMS
(Continued)

FCM	Forward Capacity Market administered by ISO-NE to procure capacity resources to meet forecasted demand and reserve requirements.
FERC	Federal Energy Regulatory Commission.
FRCC	Florida Reliability Coordinating Council.
GAAP	United States generally accepted accounting principles.
GenOn	GenOn Energy, Inc. (formerly known as RRI Energy, Inc.) and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Merger.
GenOn Americas	GenOn Americas, Inc. (formerly known as Mirant Americas, Inc.).
GenOn Americas Generation	GenOn Americas Generation, LLC (formerly known as Mirant Americas Generation, LLC).
GenOn Bowline	GenOn Bowline, LLC (formerly known as Mirant Bowline, LLC).
GenOn California North	GenOn California North, LLC (formerly known as Mirant California, LLC).
GenOn Canal	GenOn Canal, LLC (formerly known as Mirant Canal, LLC).
GenOn Chalk Point	GenOn Chalk Point, LLC (formerly known as Mirant Chalk Point, LLC).
GenOn Delta	GenOn Delta, LLC (formerly known as Mirant Delta, LLC).
GenOn Energy Holdings	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.
GenOn Energy Management	GenOn Energy Management, LLC (formerly known as Mirant Energy Trading, LLC).
GenOn Escrow	GenOn Escrow Corp.
GenOn Kendall	GenOn Kendall, LLC (formerly known as Mirant Kendall, LLC).
GenOn Lovett	GenOn Lovett, LLC, owner of the former Lovett generating facility, which was shut down on April 19, 2008, and has been demolished (formerly known as Mirant Lovett, LLC).
GenOn Marsh Landing	

	GenOn Marsh Landing, LLC (formerly known as Mirant Marsh Landing, LLC).
GenOn MD Ash Management	GenOn MD Ash Management, LLC (formerly known as Mirant MD Ash Management, LLC).
GenOn Mid-Atlantic	GenOn Mid-Atlantic, LLC (formerly known as Mirant Mid-Atlantic, LLC) and, except where the context indicates otherwise, its subsidiaries.
GenOn North America	GenOn North America, LLC (formerly known as Mirant North America, LLC).

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GLOSSARY OF CERTAIN DEFINED TERMS
(Continued)

GenOn Potomac River	GenOn Potomac River, LLC (formerly known as Mirant Potomac River, LLC).
GenOn Potrero	GenOn Potrero, LLC (formerly known as Mirant Potrero, LLC).
HAP	Hazardous Air Pollutant.
Hudson Valley Gas	Hudson Valley Gas Corporation.
IBEW	International Brotherhood of Electrical Workers.
intermediate generating units	Units designed to satisfy system requirements that are greater than baseload and less than peaking.
IRC	Internal Revenue Code of 1986, as amended.
ISO	Independent system operator.
ISO-NE	Independent System Operator-New England.
LIBOR	London InterBank Offered Rate.
LTSA	Long-term service agreement.
MACT	Maximum achievable control technology.
MADEP	Massachusetts Department of Environmental Protection.
MAEEA	Massachusetts Executive Office of Energy and Environmental Affairs.
Maryland Act	Greenhouse Gas Reduction Act of 2009.
MC Asset Recovery	MC Asset Recovery, LLC.
MDE	Maryland Department of the Environment.
Merger	The merger completed on December 3, 2010 pursuant to the Merger Agreement.
Merger Agreement	The agreement by and among Mirant Corporation, RRI Energy, Inc. and RRI Energy Holdings, Inc. dated as of April 11, 2010.
Mirant	GenOn Energy Holdings, Inc. (formerly known as Mirant Corporation) and, except where the context indicates otherwise, its subsidiaries.

MISO	Midwest Independent Transmission System Operator.
MW	Megawatt.
MWh	Megawatt hour.
NAAQS	National ambient air quality standard.
NERC	North American Electric Reliability Council.
net capacity factor	Actual net production of electricity as a percentage of net generating capacity to produce electricity.
net generating capacity	Net summer capacity.
NOL	Net operating loss.

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GLOSSARY OF CERTAIN DEFINED TERMS
(Continued)

NOV	Notice of violation.
NO_x	Nitrogen oxides.
NPCC	Northeast Power Coordinating Council.
NPDES	National pollutant discharge elimination system.
NYISO	New York Independent System Operator.
NYMEX	New York Mercantile Exchange.
NYSE	New York Stock Exchange.
OTC	Over-the-counter.
Ozone Season	The period between May 1 and September 30 of each year.
PADEP	Pennsylvania Department of Environmental Protection.
peaking generating units	Units designed to satisfy demand requirements during the periods of greatest or peak load on the system.
PEDFA	Pennsylvania Economic Development Financing Authority.
Pepco	Potomac Electric Power Company.
PG&E	Pacific Gas & Electric Company.
PJM	PJM Interconnection, LLC.
Plan	The plan of reorganization that was approved in conjunction with Mirant Corporation s emergence from bankruptcy protection on January 3, 2006.
PPA	Power purchase agreement.
PUHCA	Public Utility Holding Company Act of 2005.
REMA	GenOn REMA, LLC and its subsidiaries (formerly known as RRI Energy Mid-Atlantic Power Holdings, LLC).
reserve margin	Excess capacity over peak demand.
RFC	Reliability First Corporation.

RGGI	Regional Greenhouse Gas Initiative.
RMR	Reliability-must-run.
RPM	Model utilized by PJM to meet load serving entities forecasted capacity obligations through a forward-looking commitment of capacity resources.
RRI Energy	RRI Energy, Inc., which changed its name to GenOn Energy, Inc. in connection with the Merger.
RTO	Regional Transmission Organization.
SCR	Selective catalytic reduction emissions controls.
scrubbers	Flue gas desulfurization emissions controls.
SEC	United States Securities and Exchange Commission.

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GLOSSARY OF CERTAIN DEFINED TERMS (Continued)

Securities Act	Securities Act of 1933, as amended.
SEMA	Southeastern Massachusetts zone within ISO-NE.
SERC	SERC Reliability Corporation.
Series A Warrants	Warrants issued by Mirant on January 3, 2006, with an exercise price of $21.87 and expiration date of January 3, 2011.
Series B Warrants	Warrants issued by Mirant on January 3, 2006, with an exercise price of $20.54 and expiration date of January 3, 2011.
SO_2	Sulfur dioxide.
spark spread	The difference between the price received for electricity generated compared to the market price of the natural gas required to produce the electricity.
SWD	Surface water discharge.
Transport Rule	The EPA s Proposed Federal Implementation Plan To Reduce Interstate Transport of Fine Particulate Matter and Ozone, which would replace the CAIR.
UWUA	Utility Workers Union of America.
VaR	Value at risk.
VIE	Variable interest entity.
Virginia DEQ	Virginia Department of Environmental Quality.
WCI	Western Climate Initiative.
WECC	Western Electric Coordinating Council.
Wrightsville	Wrightsville, Arkansas power generating facility, which was sold by Mirant in the third quarter of 2005.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. These statements involve known and unknown risks and uncertainties and relate to our revenues, income, capital structure and other financial items, future events, our future financial performance or our projected business results and our view of economic and market conditions. In some cases, one can identify forward-looking statements by terminology such as may, will, should, could, objective, projection, forecast, goal, guidance, outlook, expect think, anticipate, estimate, predict, target, potential or continue or the negative of these terms or other com terminology.

Forward-looking statements are only predictions. Actual events or results may differ materially from any forward-looking statement as a result of various factors, which include:

our ability to integrate successfully the businesses following the Merger or realize cost savings and any other synergies as a result of the Merger;

our ability to enter into intermediate and long-term contracts to sell power or to hedge economically our expected future generation of power, and to obtain adequate supply and delivery of fuel for our generating facilities, at our required specifications and on terms and prices acceptable to us;

failure to obtain adequate fuel supply, including from curtailments of the transportation of natural gas;

changes in market conditions, including developments in the supply, demand, volume and pricing of electricity and other commodities in the energy markets, including efforts to reduce demand for electricity and to encourage the development of renewable sources of electricity, and the extent and timing of the entry of additional competition in our markets;

deterioration in the financial condition of our counterparties and the failure of such parties to pay amounts owed to us or to perform obligations or services due to us beyond collateral posted;

the failure of our generating facilities to perform as expected, including outages for unscheduled maintenance or repair;

hazards customary to the power generation industry and the possibility that we may not have adequate insurance to cover losses resulting from such hazards or the inability of our insurers to provide agreed upon coverage;

our failure to utilize new, or advancements in, power generation technologies;

strikes, union activity or labor unrest;

our ability to develop or recruit capable leaders and our ability to retain or replace the services of key employees;

weather and other natural phenomena, including hurricanes and earthquakes;

the cost and availability of emissions allowances;

the curtailment of operations and reduced prices for electricity resulting from transmission constraints;

our ability to execute our business plan in California, including entering into new tolling arrangements for our existing generating facilities;

our ability to execute our development plan in respect of our Marsh Landing generating facility, including obtaining and maintaining the governmental authorization necessary for construction and operation of the generating facility and completing the construction of the generating facility by mid-2013;

our relative lack of geographic diversification of revenue sources resulting in concentrated exposure to the PJM market;

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the potential of additional limitation or loss of our income tax NOLs as a result of an ownership change as defined in IRC Section 382;

war, terrorist activities, cyberterrorism and inadequate cybersecurity, or the occurrence of a catastrophic loss;

our failure to provide a safe working environment for our employees and visitors thereby increasing our exposure to additional liability, loss of productive time, other costs and a damaged reputation;

poor economic and financial market conditions, including impacts on financial institutions and other current and potential counterparties, and negative impacts on liquidity in the power and fuel markets in which we hedge economically and transact;

increased credit standards, margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts that are expected, including additional collateral costs associated with OTC hedging activities as a result of new or proposed laws, rules and regulations governing derivative financial instruments (such as the Dodd-Frank Act and related pending rulemaking proceedings);

our inability to access effectively the OTC and exchange-based commodity markets or changes in commodity market conditions and liquidity, including as a result of new or proposed laws, rules and regulations governing derivative financial instruments (such as the Dodd-Frank Act and related regulations), which may affect our ability to engage in asset management, proprietary trading and fuel oil management activities as expected, or may result in material gains or losses from open positions;

volatility in our gross margin as a result of our accounting for derivative financial instruments used in our asset management, proprietary trading and fuel oil management activities and volatility in our cash flow from operations resulting from working capital requirements, including collateral, to support our asset management, proprietary trading and fuel oil management activities;

legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the industry of generating, transmitting and distributing electricity (the electricity industry); changes in state, federal and other regulations affecting the electricity industry (including rate and other regulations); changes in tax laws and regulations to which we and our subsidiaries are subject; and changes in, or changes in the application of, environmental and other laws and regulations to which we and our subsidiaries and affiliates are or could become subject;

more stringent environmental laws and regulations (including the cumulative effect of many such regulations) and the disposition of environmental litigation that restrict our ability or render it uneconomic to operate our assets, including regulations and litigation related to air emissions;

increased regulation that limits our access to adequate water supplies and landfill options needed to support power generation or that increases the costs of cooling water and handling, transporting and disposing of ash and other byproducts;

price mitigation strategies employed by ISOs or RTOs that reduce our revenue and may result in a failure to compensate our generating units adequately for all of their costs;

legal and political challenges to or changes in the rules used to calculate payments for capacity, energy and ancillary services or the establishment of bifurcated markets, incentives or other market design changes that give preferential treatment to new generating facilities over exiting generating facilities;

the disposition of pending or threatened litigation, including environmental litigation;

the inability of our operating subsidiaries to generate sufficient cash to support our operations;

the ability of lenders under our revolving credit facility to perform their obligations;

our consolidated indebtedness and the possibility that we or our subsidiaries may incur additional indebtedness in the future;

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restrictions on the ability of our subsidiaries to pay dividends, make distributions or otherwise transfer funds to us, including restrictions on GenOn Mid-Atlantic and REMA contained in their respective operating lease documents, which may affect our ability to access the cash flows of those subsidiaries to make debt service and other payments;

our failure to comply with provisions of our operating leases, loan agreements and debt may lead to a breach and, if not remedied, result in an event of default thereunder, which could result in such lessors, lenders and debt holders exercising remedies, limit access to needed liquidity and damage our reputation and relationships with financial institutions;

covenants contained in our credit facilities, debt and leases that restrict our current and future operations, particularly our ability to respond to changes or take certain actions that may be in our long-term best interests; and

our ability to borrow additional funds and access capital markets.

Many of these risks, uncertainties and assumptions are beyond our ability to control or predict. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by cautionary statements contained throughout this report. Because of these risks, uncertainties and assumptions, you should not place undue reliance on these forward-looking statements. Furthermore, forward-looking statements speak only as of the date they are made.

Factors that Could Affect Future Performance

We undertake no obligation to update publicly or revise any forward-looking statements to reflect events or circumstances that may arise after the date of this report. Our filings and other important information are also available on our investor relations page at www.genon.com/investors.aspx.

In addition to the discussion of certain risks in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and the accompanying notes to GenOn s consolidated financial statements, other factors that could affect our future performance are set forth in Item 1A, Risk Factors.

Certain Terms

As used in this report, unless the context requires otherwise, we, us, our and GenOn refer to GenOn Energy, Inc. ar its consolidated subsidiaries, after giving effect to the Merger.

PART I

Item 1. *Business.*

On December 3, 2010, Mirant and RRI Energy completed their Merger. Mirant merged with a wholly-owned subsidiary of RRI Energy, with Mirant surviving the Merger as a wholly-owned subsidiary of RRI Energy. In connection with the all-stock, tax-free Merger, RRI Energy changed its name to GenOn Energy, Inc., Mirant stockholders received a fixed ratio of 2.835 shares of GenOn common stock for each share of Mirant common stock, and Mirant changed its name to GenOn Energy Holdings.

While RRI Energy was the legal acquirer, the Merger was accounted for as a reverse acquisition, and Mirant was deemed to have acquired RRI Energy for accounting purposes. As a consequence of the reverse acquisition accounting treatment, the historical financial statements and results of operations presented for periods prior to the Merger date are the historical statements of Mirant, except for stockholders equity which has been retroactively adjusted for the equivalent number of shares of the legal acquirer. The operations of the former RRI Energy businesses have been included in the financial statements from the date of the Merger. Specifically, the consolidated financial statements and financial and operational results of GenOn include the results of Mirant through December 2, 2010 and include the results of the combined entities from December 3, 2010, unless indicated otherwise.

Pursuant to the Plan for Mirant and certain of its subsidiaries, on January 3, 2006, Mirant emerged from bankruptcy and acquired substantially all of the assets of the old Mirant Corporation. The Plan provides that new Mirant (now named GenOn Energy Holdings) has no successor liability for any unassumed obligations of the old Mirant Corporation. The old corporation was then renamed and transferred to a trust, which is not affiliated with GenOn Energy Holdings. For further information about our corporate history, revenues, suppliers, business segments and Mirant s bankruptcy, see notes 1, 14 and 16 to our consolidated financial statements and Selected Financial Data in Item 6 of this Form 10-K.

Overview

We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States through ownership and operation of, and contracting for, power generation capacity. We are a wholesale generator with approximately 24,200 MW of net electric generating capacity in the PJM, MISO, Northeast and Southeast regions and California. We also operate integrated asset management and energy marketing organizations, including proprietary trading operations. Our customers are principally ISOs, RTOs and investor-owned utilities. Our generating portfolio is diversified across fossil fuel and technology types, operating characteristics and several regional power markets and serves customers primarily located near major metropolitan load centers.

At December 31, 2010, our generating capacity was 50% in PJM, 23% in CAISO, 10% in the Southeast, 7% in MISO and 10% in NYISO and ISO-NE. The net generating capacity of these facilities consisted of approximately 34% baseload, 46% intermediate and 20% peaking capacity. Our coal facilities generally dispatch as baseload, although some dispatch as intermediate capacity, and our gas, oil and dual fuel plants primarily dispatch as intermediate and/or peaking capacity.

Strategy

Our goal is to create long-term stockholder value across a broad range of commodity price environments. We intend to achieve this goal by:

Successfully integrating the companies and achieving cost savings targets. We expect to achieve approximately $150 million in annual cost savings through reductions in corporate overhead and support costs. We expect cost savings to result from consolidations in several areas, including headquarters, IT systems and corporate functions such as accounting, human resources and finance. Starting in January 2012, we expect to achieve the full $150 million of annual cost savings. We have estimated the total merger-related costs at

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approximately $215 million. These costs include $87 million of advisory and legal fees and $128 million of other merger-related costs, including costs to achieve the savings. These amounts include $25 million incurred by RRI Energy prior to the Merger. During 2010, the Company incurred $114 million. We expect to incur approximately $63 million, $10 million and $3 million during 2011, 2012 and 2013 and beyond, respectively. See Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Form 10-K and note 3 to our consolidated financial statements.

Continued operating and commercial expertise. We have substantial experience in the management, operation and optimization of a portfolio of diverse generating facilities. Drawing on the best practices of Mirant and RRI Energy, we intend to operate our generating facilities safely and efficiently and in an environmentally responsible manner to achieve optimal availability and performance to maximize cash flow.

Transacting to reduce variability in realized gross margin. We intend to develop and execute appropriate hedging strategies to manage risks associated with the volatility in the price at which we sell power and in the prices of fuel, emissions allowances and other inputs required to produce such power. This includes hedging over multiple years to reduce the variability in realized gross margin from our expected generation. In addition, we expect to continue to sell capacity either bilaterally or through periodic auction processes.

Investing capital prudently. Our capital investment decisions are focused on achieving an appropriate return for our stockholders. Capital investments include participating in the development or acquisition of new facilities, the maintenance of our existing facilities for long-term availability and improved commercial availability, and investments in our existing facilities to improve their competitive position.

Maintaining appropriate liquidity and capital structure. Through disciplined balance sheet management and maintaining adequate liquidity, we expect to be able to operate across a broad range of commodity price environments.

Business Segments

We have five operating segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations.

The Eastern PJM segment consists of eight generating facilities located in Maryland, New Jersey and Virginia. The Maryland and Virginia generating facilities are located near Washington, D.C.

The Western PJM/MISO segment consists of 23 generating facilities located in Illinois, Ohio and Pennsylvania.

The California segment consists of eight generating facilities and includes other business development efforts, including the Marsh Landing project.

The Energy Marketing segment consists of our proprietary trading, fuel oil management and natural gas transportation and storage activities.

The Other Operations segment consists of three generating facilities located in Massachusetts, one generating facility located in New York, three generating facilities located in Florida, one generating facility located in Mississippi and one generating facility located in Texas. For 2008, the Other Operations segment included the Lovett generating facility in New York, which was shut down on April 19, 2008 and demolished in 2009.

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The table below summarizes selected financial information of our operations by business segment for 2010:

Business Segments	Revenues		Gross Margin[1] (dollars in millions)		Operating Income (Loss)	
Eastern PJM	$ 1,710(2)	75%	$ 1,012	77%	$ (775)	239%
Western PJM/MISO	118(2)	5%	43	3%	(11)	3%
California	149	7%	126	10%	17	(5)%
Energy Marketing	54	2%	26	2%	16	(5)%
Other Operations	239	11%	100	8%	(187)	58%
Eliminations		%		%	616	(190)%
Total	$ 2,270	100%	$ 1,307	100%	$ (324)	100%

(1) Gross margin excludes depreciation and amortization.

(2) For 2010, we recorded $1.5 billion in revenues from a single counterparty (PJM) which represented 64% of our consolidated revenues. The revenues generated from this counterparty are included in our Eastern PJM, Western PJM/MISO and Energy Marketing segments.

Eliminations for revenues and gross margin are primarily related to intercompany sales of emissions allowances. Eliminations for operating income/loss also include a $616 million impairment loss related to goodwill recorded at our GenOn Mid-Atlantic subsidiary on its standalone balance sheet. The goodwill impairment loss and related goodwill balance are eliminated upon consolidation at GenOn North America and are not reflected on the consolidated balance sheet of the Company. For selected financial information about our business segments, see note 16 to our consolidated financial statements.

Eastern PJM Segment

We own or lease eight generating facilities in the Eastern PJM segment with total net generating capacity of 6,336 MW. Our Eastern PJM segment had a combined 2010 net capacity factor of 33%. The following table presents the details of our Eastern PJM generating facilities:

Facility	Net Generating Capacity (MW)[1]	Holding	Primary Fuel Type	Dispatch Type	Location	NERC Region
Chalk Point	2,401	Own	Coal/Dual/Oil	Baseload/Intermediate/Peaking	Maryland	RFC
Dickerson	844	Own/Lease[2]	Coal/Dual/Oil	Baseload/Peaking	Maryland	RFC
Gilbert	536	Own	Dual	Intermediate/Peaking	New Jersey	RFC
Glen Gardner	160	Own	Dual	Peaking	New Jersey	RFC
Morgantown	1,477	Own/Lease[2]	Coal/Oil	Baseload/Peaking	Maryland	RFC
Potomac River	482	Own	Coal	Baseload/Intermediate	Virginia	RFC

Sayreville	224	Own	Dual	Peaking	New Jersey	RFC
Werner	212	Own	Oil	Peaking	New Jersey	RFC
Total Eastern PJM	6,336					

(1) Total MW amounts reflect net summer capacity.

(2) We lease a 100% interest in the Dickerson and Morgantown baseload units through facility lease agreements expiring in 2029 and 2034, respectively. We own 307 MW and 248 MW of peaking capacity at the Dickerson and Morgantown generating facilities, respectively.

We completed the installation of scrubbers at our Chalk Point, Dickerson and Morgantown coal-fired units in the fourth quarter of 2009. We previously installed SCR systems at the Morgantown coal-fired units and one of the Chalk Point coal-fired units and a selective auto catalytic reduction system at the other Chalk

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Point coal-fired unit. In addition, we installed selective non-catalytic reduction systems at the three Dickerson coal-fired units. These controls are capable of reducing emissions of SO_2, NO_x and mercury by approximately 98%, 90% and 80%, respectively, for three of our largest coal-fired units in Maryland.

We reviewed our Chalk Point, Dickerson, Morgantown and Potomac River generating facilities for impairment as a result of our annual assessment of the goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet, which is eliminated upon consolidation at GenOn North America. Upon completion of the assessment, we determined that none of the GenOn Mid-Atlantic generating facilities was impaired at October 31, 2010.

In December 2010, PJM published an updated load forecast, which depicted a decrease in the expected demand from prior projections because of lower economic growth expectations. As a result of the load forecast, our current expectation is that there will be a decrease in the clearing prices for future capacity auctions in certain years. The decrease in projected capacity revenue caused us to update our October 2010 impairment review of GenOn Mid-Atlantic s long-lived assets. Upon completion of our assessment, which was based on the accounting guidance related to the impairment of long-lived assets, we determined that the Dickerson and Potomac River generating facilities were impaired at December 31, 2010, as the carrying value exceeded the updated December 2010 undiscounted cash flows. We recorded fourth quarter impairment losses of $523 million and $42 million on our consolidated statement of operations to reduce the carrying values of the Dickerson and Potomac River generating facilities, respectively, to their estimated fair values. In addition, as a result of the full impairment of the Potomac River generating facility, we recorded $32 million in operations and maintenance expense and corresponding liabilities associated with our commitment to reduce particulate emissions at our Potomac River generating facility as part of the agreement with the City of Alexandria, Virginia. The planned capital investment would not be recovered in future periods based on the current projected cash flows of the Potomac River generating facility. We also have $32 million included in funds on deposit and other noncurrent assets in the consolidated balance sheets, which represents the remaining balance placed in escrow as a result of the agreement with the City of Alexandria. See note 5(c) to our consolidated financial statements for further information related to our GenOn Mid-Atlantic impairment analyses.

Our generating facilities located in New Jersey may require further investment in environmental controls. See Environmental Regulation below for further information.

Western PJM/MISO Segment

We own or lease 23 generating facilities in the Western PJM/MISO segment with total net generating capacity of 7,483 MW. Our Western PJM/MISO segment had a combined 2010 net capacity factor of 36%. The following table presents the details of our Western PJM/MISO generating facilities:

Facility	Net Generating Capacity (MW)(1)	Holding	Primary Fuel Type	Dispatch Type	Location	NERC Region
Aurora	878	Own	Natural gas	Peaking	Illinois	RFC
Avon Lake	753	Own	Coal/Oil	Baseload/Peaking	Ohio	RFC
Blossburg	19	Own	Natural gas	Peaking	Pennsylvania	RFC
Brunot Island	289	Own	Natural gas/Oil	Intermediate/Peaking	Pennsylvania	RFC
Cheswick	565	Own	Coal	Baseload	Pennsylvania	RFC
Conemaugh	281	Lease(2)	Coal/Oil	Baseload/Peaking	Pennsylvania	RFC

Elrama	460	Own	Coal	Baseload	Pennsylvania	RFC
Hamilton	20	Own	Oil	Peaking	Pennsylvania	RFC
Hunterstown	60	Own	Dual	Peaking	Pennsylvania	RFC
Hunterstown CCGT	810	Own	Natural gas	Intermediate	Pennsylvania	RFC
Keystone	284	Lease(2)	Coal/Oil	Baseload/Peaking	Pennsylvania	RFC
Mountain	40	Own	Dual	Peaking	Pennsylvania	RFC

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Facility	Net Generating Capacity (MW)(1)	Holding	Primary Fuel Type	Dispatch Type	Location	NERC Region
New Castle	330	Own	Coal/Oil	Baseload/Peaking	Pennsylvania	RFC
Niles	242	Own	Coal/Oil	Baseload/Peaking	Ohio	RFC
Orrtanna	20	Own	Oil	Peaking	Pennsylvania	RFC
Portland	570	Own	Coal/Dual	Baseload/Intermediate/Peaking	Pennsylvania	RFC
Seward	525	Own	Coal	Baseload	Pennsylvania	RFC
Shawnee	20	Own	Oil	Peaking	Pennsylvania	RFC
Shawville	603	Lease(2)	Coal/Oil	Baseload/Peaking	Pennsylvania	RFC
Shelby	344	Own	Natural gas	Peaking	Illinois	SERC
Titus	274	Own	Coal/Dual	Baseload/Peaking	Pennsylvania	RFC
Tolna	39	Own	Oil	Peaking	Pennsylvania	RFC
Warren	57	Own	Dual	Peaking	Pennsylvania	RFC
Total Western PJM/MISO	7,483					

(1) Total MW amounts reflect net summer capacity.

(2) We lease 100%, 16.67% and 16.45% interests in three Pennsylvania facilities, Shawville, Keystone and Conemaugh, respectively, through facility lease agreements expiring in 2026, 2034 and 2034, respectively. We operate the Shawville, Keystone and Conemaugh facilities. The table includes our net share of the capacity of these facilities.

We expect the Avon Lake, New Castle and Niles generating facilities to move from the MISO region to the PJM region in June 2011 as a result of the FERC s approval of the transfer.

In 2009 and 2010, we installed scrubbers at the Keystone and Cheswick generating facilities to reduce the SO_2 emissions from these facilities. As a result, the number of SO_2 allowances we will need to purchase in the market to comply with current regulations is reduced. These scrubbers are capable of removing up to 98% of the SO_2 from the exhaust as well as reducing mercury emissions by up to 80%. The units had previously been retrofitted with SCRs to reduce NO_x emissions.

California Segment

We own eight generating facilities in California with total net generating capacity of 5,725 MW. Our California segment generating facilities had a combined 2010 net capacity factor of 2%. The following table presents the details of our California generating facilities:

	Net Generating Capacity		Primary Fuel			NERC

Facility	(MW)[1]	Holding	Type	Dispatch Type	Location	Region
Contra Costa	674	Own	Natural gas	Intermediate	California	WECC
Coolwater	608	Own	Natural gas	Intermediate	California	WECC
Ellwood	54	Own	Natural gas	Peaking	California	WECC
Etiwanda	640	Own	Natural gas	Intermediate	California	WECC
Mandalay	560	Own	Natural gas	Intermediate/Peaking	California	WECC
Ormond Beach	1,516	Own	Natural gas	Intermediate	California	WECC
Pittsburg	1,311	Own	Natural gas	Intermediate	California	WECC
Potrero[2]	362	Own	Natural gas/Oil	Intermediate/Peaking	California	WECC
Total California	5,363(2)					

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(1) Total MW amounts reflect net summer capacity.

(2) We shut down the Potrero facility on February 28, 2011. The total net generating capacity for the California segment per the table excludes Potrero. See below for further discussion.

In the third quarter of 2009, GenOn Potrero executed a settlement agreement with the City and County of San Francisco in which it agreed to shut down the Potrero generating facility when it is no longer needed for reliability, as determined by the CAISO. That settlement agreement became effective in November 2009. In December 2010, the CAISO provided GenOn Potrero with the requisite notice of termination of the RMR agreement. On January 19, 2011, at the request of GenOn Potrero, the FERC approved changes to GenOn Potrero s RMR agreement to allow the CAISO to terminate the RMR agreement effective February 28, 2011. On February 28, 2011, the Potrero facility was shut down.

Our existing generating facilities in California depend almost entirely on payments they receive to operate in support of system and local reliability through the sale of resource adequacy capacity to load serving entities. The energy, capacity and ancillary services markets, as currently constituted, will not support the capital expenditures necessary to repower or reconstruct our facilities. In order to obtain the necessary capital support for repowering or reconstructing our facilities, we would need to obtain contracts with creditworthy buyers. Absent that, our existing generating facilities in California will be commercially viable only as long as they have contracts for their capacity.

Energy Marketing Segment

Our Energy Marketing segment includes our proprietary trading, fuel oil management and natural gas transportation and storage activities. This activity includes the purchase and sale of electricity, fuel and emissions allowances, sometimes through financial derivatives.

Using our fundamental understanding of the markets in which we operate, we support our commercial asset management activities as well as engage in proprietary trading when we identify opportunities. We engage in fuel oil management activities to hedge economically the fair value of our physical fuel oil inventories, optimize the approximately three million barrels of storage capacity that we own or lease, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products. We engage in natural gas transportation and storage activities to optimize our physical natural gas and storage positions and manage the physical gas requirements for a portion of our assets.

Proprietary trading, fuel oil management and natural gas transportation and storage activities together will typically comprise less than 5% of our realized gross margin. All of our commercial activities are governed by a comprehensive risk management policy, which includes limits on the size of volumetric positions and VaR for our proprietary trading and fuel oil management activities and requires all incremental natural gas transportation and natural gas storage activities to be risk reducing. For 2010, our combined average daily VaR for proprietary trading and fuel oil management activities was $2 million.

Other Operations Segment

We own or lease four generating facilities in the Northeast region and five generating facilities in the Southeast region with total net generating capacity of 5,055 MW. Other Operations had a combined 2010 net capacity factor of 8%. Other Operations is comprised of our generating facilities located in Massachusetts,

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New York, Florida, Mississippi and Texas. The following table presents the details of our Other Operations generating facilities:

Facility	Net Generating Capacity (MW)(1)	Holding	Primary Fuel Type	Dispatch Type	Location	NERC Region
Bowline	1,139	Own	Dual	Intermediate	New York	NPCC
Canal	1,126	Own	Dual/Oil	Intermediate	Massachusetts	NPCC
Choctaw	800	Own	Natural gas	Baseload	Mississippi	SERC
Indian River(2)	586	Own	Dual	Intermediate	Florida	FRCC
Kendall	256	Own	Natural gas/Oil/Dual	Baseload/Peaking	Massachusetts	NPCC
Martha s Vineyard	14	Own	Oil	Peaking	Massachusetts	NPCC
Osceola	450	Own	Dual	Peaking	Florida	FRCC
Sabine(3)	54	Own	Natural gas	Baseload	Texas	SERC
Vandolah	630	Lease(4)	Dual	Peaking	Florida	FRCC
Total Other Operations	5,055					

(1) Total MW amounts reflect net summer capacity.

(2) The Indian River generating facility was mothballed in January 2010, other than during the third quarter of 2010 when one unit operated under a PPA.

(3) We own a 50% equity interest in the Sabine facility located in east Texas having a net generating capacity of 108 MW. An unaffiliated party owns the other 50% and an affiliated party to the other owner operates the facility. The table includes our net share of the capacity of this facility.

(4) We are party to a tolling agreement that expires in May 2012 and entitles us to purchase and dispatch 100% of this facility s electric generating capacity. The tolling agreement is treated as an operating lease for accounting purposes.

During the second quarter of 2010, the NYISO issued its annual peak load and energy forecast in its Load and Capacity Data report (the Gold Book). The Gold Book reports projected electricity supply and demand for the New York control area for the next ten years. The most recent Gold Book projects a significant decrease in future electricity demand as a result of current economic conditions and the expected future effects of demand-side management programs in New York. The expected reduction in future demand as a result of demand-side management programs is being driven primarily by an energy efficiency program being instituted within the State of New York that will seek to achieve a 15% reduction from 2007 energy volumes by 2015. As a result of the projections in the Gold Book, we evaluated the Bowline generating facility for impairment in the second quarter of 2010. The sum of the probability weighted undiscounted cash flows for the Bowline generating facility exceeded the carrying value. As a result, we did not record an impairment loss for the Bowline generating facility during the second quarter of 2010.

GenOn Bowline has challenged its property tax assessment for the 2009 and 2010 tax years. Although the assessment for the 2010 tax year was reduced significantly from the assessment received in 2009, the assessment continues to exceed significantly the estimated fair value of the generating facility.

In the fourth quarter of 2010, we identified certain operational issues that reduced the available capacity of the Bowline generating facility. We are in the process of evaluating long-term solutions for the generating facility, but our current expectation is that the reduction in available capacity could extend through 2012. In the fourth quarter of 2010, we again evaluated the Bowline generating facility for impairment because of the expected extended reduction in available capacity together with the pending property tax litigation and the effect of supply and demand assumptions in the NYISO s Gold Book. The sum of the probability weighted undiscounted cash flows for the Bowline generating facility exceeded the carrying value. As a result, we did not record an impairment loss for the Bowline generating facility during 2010. See note 5(c) to our consolidated financial statements for further information related to our impairment analysis of the Bowline generating facility.

ISO-NE previously had determined that, at times, it was necessary for the Canal generating facility to operate to meet local reliability criteria for SEMA when it is not economic for the Canal generating facility to operate based upon prevailing market prices. When the Canal generating facility operates to meet local reliability criteria, we are compensated at the price we bid into the ISO-NE, pursuant to ISO-NE market rules, rather than at the market price. During 2009, NSTAR Electric Company completed planned upgrades to the SEMA transmission system. These upgrades have reduced the need for the Canal generating facility to operate and caused a reduction in energy gross margin compared to historical levels. The final phase of these transmission upgrades was completed in the third quarter of 2009 and as a result, the capacity factor for the Canal generating facility dropped as compared to 2008. With the completion of the transmission upgrades and because of the Canal generating facility s high fuel costs relative to other generation in the northeast market, we expect that the future revenues of the Canal generating facility will be principally capacity revenue from the ISO-NE forward capacity market.

The Kendall generating facility, which is a cogeneration facility, has long-term agreements under which it sells steam.

Pursuant to a consent decree, we discontinued operation of units 4 and 5 at our Lovett generating facility in New York in May 2007 and April 2008, respectively. In addition, we discontinued operation of unit 3 at the Lovett generating facility in May 2007 because it was uneconomic to operate the unit. We completed the demolition of the Lovett generating facility in 2009.

Asset Management

We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States, including ISOs and RTOs, power aggregators, retail providers, electric-cooperative utilities, other power generating companies and load serving entities. Our commercial operations consist primarily of dispatching electricity, hedging the generation and sale of electricity, selling capacity, procuring and managing fuel and providing logistical support for the operation of our facilities (for example, by procuring transportation for coal and natural gas).

Our strategy is to enter into economic hedges forward sales of electricity and forward purchases of fuel and emissions allowances to manage the risks associated with volatility in prices for electricity, fuel and emissions allowances and to achieve more predictable financial results. In addition, given the high correlation between natural gas prices and electricity prices in many of the markets in which we operate, we enter into forward sales of natural gas to hedge economically our exposure to changes in the price of electricity. We procure our hedges in OTC transactions or on exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with buyers and sellers, using futures, forwards, swaps and options. Our hedges cover various periods, including several years. See Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Form 10-K for our aggregate hedge levels based on expected generation for 2011 to 2015. In addition, see Item 1A, Risk Factors Risks Related to Economic and Financial Market Conditions Greater regulation of energy contracts for a discussion of the risks of implementation of the Dodd-Frank Act on our ability to hedge economically our generation, including potentially reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with such activities.

We sell capacity either bilaterally or through periodic auction processes in each ISO and RTO market in which we participate. Our capacity sales primarily occur through the PJM RPM and ISO-NE FCM auctions, but also in CAISO, MISO, NYISO and other markets where we enter into agreements with counterparties. We expect that a substantial portion of our PJM capacity will continue to be sold in PJM up to three years in advance. Revenue from these capacity sales is determined by market rules designed to ensure regional reliability, encourage competition and reduce energy price volatility. These capacity sales provide an important source of predictable revenues for us over the contracted periods. At January 31, 2011, total projected contracted capacity and PPA revenues for which prices have been set for 2011 through 2014 are $3.1 billion.

Power

We hedge economically a substantial portion of our Eastern PJM coal-fired baseload generation and certain of our other generation. We generally do not hedge our intermediate and peaking units for tenors greater than 12 months. A significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices.

Although standard industry OTC transactions make up a substantial portion of our economic hedge portfolio, at times we sell non-standard, structured products to customers.

Several of our California, Florida and Mississippi generating facilities typically operate under contracts for their capacity or energy. In California, GenOn Delta has entered into agreements with PG&E to provide electricity from our natural gas-fired units in service at Contra Costa and Pittsburg. With respect to Contra Costa units 6 and 7, GenOn Delta is providing 674 MW of capacity to PG&E for 2011 under a multi-year tolling agreement into which we entered in 2006. GenOn Delta entered into a new agreement with PG&E on September 2, 2009 for the 674 MW at Contra Costa units 6 and 7 for the period from November 2011 through April 2013. At the end of the agreement, and subject to any necessary regulatory approval, GenOn Delta has agreed to retire Contra Costa units 6 and 7, which began operations in 1964, in furtherance of state and federal policies to retire aging power plants that utilize once-through cooling technology. In addition, GenOn Delta entered into an agreement with PG&E on October 28, 2010 for 1,159 MW of capacity from Pittsburg units 5, 6 and 7 for three years commencing January 1, 2011, with options for PG&E to extend the agreement for each of 2014 and 2015. Under the respective agreements, GenOn Delta will receive monthly capacity payments with bonuses and/or penalties based on heat rate and availability. On September 2, 2009, GenOn Marsh Landing entered into a ten-year PPA with PG&E for 760 MW of natural gas-fired peaking generation to be constructed adjacent to our Contra Costa generating facility near Antioch, California. Construction of the Marsh Landing generating facility is expected to be completed by mid-2013.

Fuel

We enter into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase most of our coal from a small number of suppliers under contracts with terms of varying lengths, some of which extend to 2013 and one that extends to 2020. See Quantitative and Qualitative Disclosures About Market Risk in Item 7A of this Form 10-K for discussion of our coal agreement risk. For our oil-fired units, we typically purchase fuel from a small number of suppliers either in the spot market or under contracts with terms of varying lengths. For our natural gas-fired facilities, in addition to purchasing natural gas, we arrange for and schedule its transportation through pipelines. To perform a portion of these functions, we lease natural gas transportation and storage capacity. We sell excess fuel supplies to third parties.

We receive coal at our generating facilities primarily by rail and truck. In addition, we can receive coal by barge at three of our plants: our Morgantown generating facility completed construction of a barge unloader in 2008 that enables us to receive coal from domestic and international sources; and our Cheswick and Elrama generating facilities also have barge unloading facilities, which are typically used to receive domestic coal. We have coal blending facilities at our Cheswick, Morgantown and Titus generating facilities that allow for greater flexibility of coal supply by allowing various coal qualities to be blended while also meeting emissions targets. We monitor coal supply and delivery logistics carefully and, despite occasional interruptions of planned deliveries, to date we have managed to avoid any significant detrimental effects on our operations. Because of the risk of disruptions in our coal supply, we strive to maintain adequate targeted levels of coal inventories at our coal-fired facilities. Interruptions to planned or contracted deliveries can result from a variety of factors, including operational issues of coal suppliers, lack of, or constraints in, coal transportation (including rail system and river system disruptions) and adverse weather conditions.

Emissions

Our commercial operations manage the acquisition and use of emissions allowances for our generating facilities. Our generating facilities in Maryland, Massachusetts, New Jersey and New York are subject to the RGGI, a multi-state cap-and-trade program to reduce CO_2 emissions from units of 25 MW or greater. The RGGI became effective on January 1, 2009. To comply, we are required to purchase allowances, either through periodic auctions or open market transactions, to offset our CO_2 emissions. In 2010 and 2009, we recognized approximately $34 million and $45 million, respectively, in cost of fuel, electricity and other products as a result of our compliance with the RGGI.

In May 2010, the Montgomery County Council imposed a levy on major emitters of CO_2 in Montgomery County, Maryland which we estimate will impose on the Dickerson generating facility of GenOn Mid-Atlantic an additional $10 million to $15 million per year in levies owed to Montgomery County. During 2010, we recognized $8 million in levies in operations and maintenance expense. See note 18 to our consolidated financial statements for further discussion of the action filed against Montgomery County in the United States District Court for the District of Maryland by GenOn Mid-Atlantic.

Coal Combustion Byproducts

Existing state and federal rules require the proper management and disposal of wastes and other materials. We produce byproducts from our coal-fired generating units, including ash and gypsum. We actively manage the current and planned disposition of each of these byproducts. All of our ash disposal facilities are dry landfills (although we do use ponds to dewater ash at some facilities). Our disposal plan for ash includes land filling at our existing ash management facilities, purchasing and permitting additional disposal sites, using third parties to handle and dispose of the ash, and constructing an ash beneficiation facility at our Morgantown site to make the ash more suitable for sale to third parties for the production of concrete as well as other beneficial uses. We commenced construction of the ash beneficiation facility in February 2011 and expect to complete it in 2012. Our disposal plan for gypsum includes disposing of it in approved landfills and selling it to third parties for use in the production of drywall. Currently, we expect to spend approximately $130 million over the next five years for ash landfill expansions, closures and for building an ash beneficiation facility.

There is increased focus on the regulation of coal combustion products and, if the manner in which they are regulated changes, we may be required to change our management practices for these byproducts and/or incur additional costs.

Competitive Environment

The power generating industry is capital intensive and highly competitive. Our competitors include regulated utilities, merchant energy companies, financial institutions and other companies. For a discussion of competitive factors see Item 1A, Risk Factors. Coal-fired, natural gas-fired, nuclear and hydroelectric generation currently account for approximately 45%, 24%, 20% and 6%, respectively, of the electricity produced in the United States. Other energy sources account for the remaining 5% of electricity produced.

Wholesale power generation is highly fragmented compared to other commodity industries. There is wide variation in terms of the capabilities, resources, nature and identity of the companies with which we compete. Our competitive advantages include the following:

Reliability of our future cash flows. Our large coal generating fleet is exposed to the relationship between the cost of production and the price of the power produced. This relationship, commonly referred to as the dark spread, fluctuates with the cost of coal and the price of power. We hedge economically a substantial portion of our Eastern PJM coal-fired baseload generation and certain of our other generation. We hedge our output at varying levels several years in advance because the price of electricity is volatile. In addition, we enter into contracts to hedge economically our future needs of coal, which is our primary fuel.

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Locational advantages. Many of our generating facilities are located in or near metropolitan areas, including Boston, New York City, Pittsburgh, San Francisco, Southern California/Los Angeles and Washington, D.C. The supply-demand balance in some of these markets is forecasted to become constrained, though at a slower rate than forecasted before the economic downturn, and increasingly dependent on power imported from other regions to sustain reliability. Although transmission projects are planned in these markets to bring capacity from neighboring regions, the timing of these projects is subject to delays and uncertainty.

Room to expand at our existing sites. We have sufficient room and infrastructure at many of our existing sites to increase significantly our generating capacity when market rules and conditions warrant. In addition to reduced costs for developing new generation at existing sites because of our ownership of the land and our ownership of and/or access to infrastructure, regulators frequently prefer that new generation be added at existing sites (brownfield development) rather than at new sites (greenfield development). We continue to consider these and other investment opportunities.

Given the substantial time required to permit and construct new power plants, the process to add generating capacity must begin years in advance of anticipated growth in demand. A number of ISOs and RTOs, including those in markets in which we operate, have implemented capacity markets as a way to encourage construction of additional generation when market conditions warrant. Over the last several years, very little new generation has been constructed as a result of the economic downturn in recent years and programs to reduce the demand for electricity which have resulted in a decrease in the rate at which the long-term demand for electricity is forecasted to grow. Also, the costs to construct new generating facilities have been rising, and there is substantial environmental opposition to building either coal-fired or nuclear plants.

In some markets, state regulators have proposed initiatives to provide long-term contracts for new generating capacity. In December 2010, the Maryland Public Service Commission sought comments on a possible request for proposals for new generating facilities. The draft request for proposals would require any such new generation to bid into the capacity markets in a manner that would ensure clearing in the market. The draft request provides for project submittals on July 29, 2011. We filed comments on the draft request for proposals on January 28, 2011, noting there is no need for additional capacity at this time. If the request for proposals is issued as currently drafted, it could have a negative effect on capacity prices in PJM in future years.

On January 28, 2011, New Jersey enacted legislation which requires the Board of Public Utilities to implement a Long-Term Capacity Agreement Pilot Program providing for new generating capacity in the state. The new generating capacity would be required to participate and be accepted as a capacity resource in the PJM capacity market. If the New Jersey agreement for new capacity is implemented as required by the statute, it could have a negative effect on capacity prices in PJM in future years. On February 1, 2011, a group of which we are a member initiated a proceeding at the FERC seeking changes in the PJM tariff to prevent interference with the capacity markets from efforts such as the New Jersey legislation and the Maryland request for proposals. On February 9, 2011, we joined a group of companies that filed suit in the U.S. District Court for New Jersey asking the court to declare the New Jersey legislation unconstitutional.

In addition, as a result of initiatives at both the federal and state level, new construction of renewable resources, including solar and wind, has occurred or is planned.

There are proposed upgrades to the transmission systems in some of the markets in which we operate that could mitigate the need for existing marginal generating capacity and for additional generating capacity. To the extent that these upgrades are completed, prices for electricity and capacity could be lower in some of our markets than they might otherwise be.

The prices for power and natural gas remain low compared to several years ago. The energy gross margin from our generating facilities is negatively affected by these price levels. For that portion of the volumes of generation that we have hedged, we are generally economically neutral to subsequent changes in commodity prices because our realized gross margin will reflect the contractual prices of our power and fuel contracts. We continue to add economic hedges, including to maintain projected levels of cash flows from operations for future periods to help support continued compliance with the covenants in our debt and lease agreements. We have implemented seasonal operating models at some of our facilities to address the effect of depressed power and commodity prices on the margins earned at these facilities.

Concern over climate change and air emissions have led to significant legislative and regulatory efforts at the state and federal level. The costs of compliance with such efforts could affect our ability to compete in the markets in which we operate, especially with our coal-fired generating facilities. See Environmental Regulation later in the section for further discussion.

Seasonality

For information on the effect of seasonality on our business, see Risk Factors in Item 1A of this Form 10-K and note 17 to our consolidated financial statements.

Regulatory Environment

The electricity industry is regulated extensively at the federal, state and local levels. At the federal level, the FERC has exclusive jurisdiction under the Federal Power Act over sales of electricity at wholesale and the transmission of electricity in interstate commerce. Each of our subsidiaries that owns or leases a generating facility selling at wholesale or that markets electricity at wholesale is a public utility subject to the FERC s jurisdiction under the Federal Power Act. These subsidiaries must comply with certain FERC reporting requirements and FERC-approved market rules and they are subject to FERC oversight of mergers and acquisitions, the disposition of facilities under the FERC s jurisdiction and the issuance of securities.

The FERC has authorized our subsidiaries that are public utilities under the Federal Power Act to sell wholesale energy, capacity and certain ancillary services at market-based rates. The majority of the output of the generating facilities owned by our subsidiaries is sold pursuant to this market-based rate authorization, although our Potrero station sold its output under a cost-based RMR agreement through February 2011 for which separate rate authorization was granted by the FERC. The FERC could revoke or limit our market-based rate authority if it determined that we possess insufficiently mitigated market power in a regional electricity market. Under the Natural Gas Act, our subsidiaries that sell natural gas for resale are deemed by the FERC to have blanket certificate authority to undertake these sales at market-based rates.

The FERC requires that our public utility subsidiaries with market-based rate authority and our subsidiaries with blanket certificate authority adhere to general rules against market manipulation as well as certain market behavior rules and codes of conduct. If any of our subsidiaries were found to have engaged in market manipulation, the FERC has the authority to impose a civil penalty of up to $1 million per day per violation. In addition to the civil penalties, if any of our subsidiaries were to engage in market manipulation or violate the market behavior rules or codes of conduct, the FERC could require a disgorgement of profits or revoke the subsidiary s market-based rate authority or blanket certificate authority. If the FERC were to revoke market-based rate authority, our affected public utility subsidiary would have to file a cost-based rate schedule for all or some of its sales of electricity at wholesale.

In 2006, the FERC certified the NERC as the national energy reliability organization. The NERC is now responsible for the development and enforcement of mandatory reliability standards for the electric power system. Each of our subsidiaries selling electricity at wholesale is responsible for complying with the reliability standards in the region in which it operates. The NERC has the ability to assess financial penalties for non-compliance with the reliability standards, which penalties can, depending on the nature of the non-compliance, be significant. In addition to complying with the NERC standards, each of our entities selling electricity at wholesale must comply with the reliability standards of the regional reliability council for the NERC region in which its sales occur.

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The vast majority of our facilities operate in markets administered by ISOs and RTOs. In areas where ISOs or RTOs control the regional transmission systems, market participants have access to broader geographic markets than in regions without ISOs and RTOs. ISOs and RTOs operate day-ahead and real-time energy and ancillary services markets, typically governed by FERC-approved tariffs and market rules. Some ISOs and RTOs also operate capacity markets. Changes to the applicable tariffs and market rules may be requested by the ISO or RTO, or by other interested persons, including market participants and state regulatory agencies, and such proposed changes, if approved by the FERC, could have a significant effect on our operations and financial results. Although participation in ISOs and RTOs by public utilities that own transmission has been, and is expected to continue to be, voluntary, the majority of such public utilities in California, Illinois, Maryland, Massachusetts, New Jersey, New York, Ohio, Pennsylvania and Virginia have joined the applicable ISO and RTO.

Our subsidiaries owning generating facilities have made such filings, and received such orders, as are necessary to obtain exempt wholesale generator status under the PUHCA and the FERC s regulations thereunder. Provided all of our subsidiaries owning or leasing generating facilities continue to be exempt wholesale generators, or are qualifying facilities under the Public Utility Regulatory Policies Act of 1978, we and our intermediate holding companies owning direct or indirect interests in those subsidiaries will remain exempt from the accounting, record retention or reporting requirements that PUHCA imposes on holding companies.

State and local regulatory authorities historically have overseen the distribution and sale of electricity at retail to the ultimate end user, as well as the siting, permitting and construction of generating and transmission facilities. Our existing generating facilities are subject to a variety of state and local regulations, including regulations regarding the environment, health and safety and maintenance and expansion of the facilities.

We hedge economically a substantial portion of our Eastern PJM coal-fired baseload generation and certain of our other generation. A significant portion of such hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices. The Dodd-Frank Act, which was enacted in July 2010 in response to the global financial crisis, increases the regulation of transactions involving OTC derivative financial instruments. The statute provides that standardized swap transactions between dealers and large market participants will have to be cleared and traded on an exchange or electronic platform. Although the provisions and legislative history of the Dodd-Frank Act provide strong evidence that market participants, such as GenOn, which utilize OTC derivative financial instruments to hedge economically commercial risks are not to be subject to these clearing and exchange-trading requirements, it is uncertain what the final implementing regulations to be issued by the CFTC and SEC will provide. The effect of the Dodd-Frank Act on our business depends in large measure on pending CFTC and SEC rulemaking proceedings and, in particular, the final definitions for the key terms Swap Dealer and Major Swap Participant in the Dodd-Frank Act. The CFTC and SEC issued a proposed rulemaking to set final definitions for the terms Swap Dealer and Major Swap Participant, among others. Entities defined as Swap Dealers and Major Swap Participants will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. As proposed, the Swap Dealer definition in particular is ambiguous, subjective and could be broad enough to encompass some energy companies. Such regulations could materially affect our ability to hedge economically our generation by reducing liquidity in the energy and commodity markets and, if we were required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with such activities. See Item 1A, Risk Factors Risks Related to Economic and Financial Market Conditions Greater regulation of energy contracts for additional information.

Under the Dodd-Frank Act, the CFTC now has the authority to set position limits not only on contracts listed by designated contract markets but also for swap contracts that perform or affect a significant price discovery function. As a result of the significant amendments to the Commodity Exchange Act by the Dodd-Frank Act, the CFTC withdrew, in August 2010, the January 2010 notice of proposed rulemaking in which it proposed to adopt all-months-combined, single (non-spot) month and spot-month position limits for exchange-listed natural gas, crude oil, heating oil and gasoline futures and options contracts. The CFTC plans to issue a notice of rulemaking proposing position limits for regulated exempt commodity contracts, including energy commodity contracts, in early 2011.

In addition to the upcoming position limit rulemakings under the Dodd-Frank Act, the CFTC has designated and put into effect position limits for certain electricity and natural gas contracts designated as significant price discovery contracts, including contracts based on CAISO and PJM West Hub locational marginal pricing that we trade on the Intercontinental Exchange, Inc. Designations put into effect to date have not had a material effect on our business. We continue to monitor the rulemaking proceeding on the remaining contracts.

PJM Region. Our Eastern and Western PJM generating facilities sell electricity into the markets operated by PJM. We have access to the PJM transmission system pursuant to PJM s Open Access Transmission Tariff. PJM operates the PJM Interchange Energy Market, which is the region s spot market for wholesale electricity, provides ancillary services for its transmission customers, performs transmission planning for the region and economically dispatches generating facilities. PJM administers day-ahead and real-time single clearing price markets and calculates electricity prices based on a locational marginal pricing model. A locational marginal pricing model determines a price for energy at each node in a particular zone taking into account the limitations and losses on transmission of electricity into the zone, resulting in a higher zonal price when less expensive energy cannot be imported from another zone. Generation owners in PJM are subject to mitigation, which limits the prices that they may receive under certain specified conditions.

Load-serving entities within PJM are required to have adequate sources of generating capacity. Our generating facilities located in the Eastern and Western PJM region that sell electricity into the PJM market participate in the RPM forward capacity market. The PJM RPM capacity auctions are designed to provide forward prices for capacity that ensure that adequate resources are in place to meet the region s demand requirements. PJM has conducted seven RPM capacity auctions and we began receiving payments in June 2007 as a result of the first auction. Certain market participants have challenged the results of the RPM auctions that set capacity payments under the RPM provisions of PJM s tariff for the twelve month periods beginning June 1, 2008, June 1, 2009 and June 1, 2010. The FERC rejected those challenges and its orders were affirmed by the D.C. Circuit. See Complaint Challenging Capacity Rates Under the RPM Provisions of PJM s Tariff in note 18 to our consolidated financial statements for a discussion of the challenges.

Since 2008, annual auctions have been conducted to procure capacity three years prior to each delivery period. The first annual auction took place in May 2008, for the provision of capacity from June 1, 2011 to May 31, 2012. PJM continues to revise elements of the RPM provisions of its tariff, both pursuant to those provisions and on its own volition or at the request of its stakeholders. These revisions must be filed with and approved by the FERC, and we, either individually or as part of a group, are actively involved at the FERC to protect our interests. See Competitive Environment for our involvement at the FERC.

MISO. Our MISO generating facilities sell electricity into the markets operated by MISO. MISO manages the transmission system and provides open access to its transmission system and markets to all market participants on an equal basis. MISO operates physical and financial energy markets using a locational marginal pricing model, which calculates a price for every generator and load point within MISO similar to the model utilized by PJM. MISO operates day-ahead and real-time markets into which generators can offer to provide energy. MISO does not administer a centralized capacity market. MISO implemented the Ancillary Services Market (Regulation and Operating Reserves) on January 6, 2009 and implemented an enforceable Planning Reserve Margin for each planning year effective June 1, 2009. A feature of the Ancillary Services Market is the addition of scarcity pricing that, during supply shortages, can raise the combined price of energy and ancillary services significantly higher than the previous cap of $1,000/MWh.

California. Our California generating facilities are located inside the CAISO s control area. On April 1, 2009, the CAISO implemented its Market Redesign and Technology Update (MRTU). MRTU s key components include locational marginal pricing of energy similar to the RTO/ISO markets in the east, a day-ahead market in addition to the existing real-time market, a more effective congestion management system and an increase in the existing bid caps. The CAISO also schedules transmission transactions and arranges for necessary ancillary services. Most sales in California are pursuant to bilateral contracts, but a significant percentage of electrical energy is sold in the day-ahead and real-time market. The CAISO does not operate a wholesale capacity market.

Other Operations. Our Bowline generating facility participates in a market administered by the NYISO. The NYISO provides statewide transmission service under a single tariff and interfaces with neighboring market control areas. To account for transmission congestion and losses, the NYISO calculates energy prices using a locational marginal pricing model. The NYISO also administers a spot market for energy, as well as markets for installed capacity and services that are ancillary to transmission service. The NYISO s locational capacity market utilizes a demand curve mechanism to determine monthly capacity prices to be paid to suppliers for three capacity zones: New York City, Long Island and Rest of State. Our facility is located in the Rest of State capacity zone.

Our Canal, Kendall and Martha s Vineyard generating facilities participate in a market administered by ISO-NE. GenOn Energy Management is a member of the New England Power Pool, which is a voluntary association of electric utilities and other market participants in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and which functions as an advisory organization to ISO-NE. As the RTO for the New England region, ISO-NE is responsible for the operation of transmission systems and for the administration and settlement of the wholesale electric energy, capacity and ancillary services markets. ISO-NE utilizes a locational marginal pricing model similar to the model used in PJM, MISO and NYISO.

On March 6, 2006, a settlement proposal was filed with the FERC among ISO-NE and multiple market participants for the FCM under which annual capacity auctions would be conducted for supply three years in advance of provision. The settlement provided for a four-year transition period during which capacity suppliers receive a set price for their capacity commencing on December 1, 2006, with price escalators through May 31, 2010. Beginning December 1, 2006, our generating facilities began receiving capacity revenues under the FCM transition period. On June 1, 2010, our generating facilities began receiving capacity revenues based upon the auction results.

Our Choctaw, Sabine, Indian River and Osceola generating facilities located in the Southeast region do not operate in a market that is operated by an RTO or ISO. Opportunities to negotiate bilateral contracts and long-term transactions with investor owned utilities, municipalities and cooperatives exist within this region. In addition to entering into bilateral transactions, there is a limited opportunity to sell into the short-term market. Access to the transmission system in this region to which the generating facility is interconnected is governed by the FERC approved terms and conditions of the applicable transmission provider s open access transmission tariff. In the Entergy sub-region, which the Choctaw facility can access, Southwest Power Pool has been designated as the Independent Coordinator of Transmission. In this capacity, the Independent Coordinator of Transmission provides oversight of the Entergy transmission system.

Environmental Regulation

Our business is subject to extensive environmental regulation by federal, state and local authorities. We must comply with applicable laws and regulations, and obtain and comply with the terms of government issued permits. These requirements relate to a broad range of our activities, including the discharge of materials into the air, water and soil; the proper handling of solid, hazardous and toxic materials and waste; noise and safety, and health standards applicable to the workplace. Some of these requirements are under revision or in dispute, and some new requirements are pending or under consideration. Our costs of complying with environmental laws and permits are substantial, including significant environmental capital expenditures. See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Expenditures and Capital Resources for additional information.

Air Emissions Regulations

The Clean Air Act and similar state laws impose significant environmental requirements on our generating facilities. The Clean Air Act mandates a broad range of requirements concerning air quality, air emissions, operating practices and pollution control equipment. Under the Clean Air Act, the EPA sets NAAQS for pollutants thought to be harmful to public health and the environment, including SO_2, NO_x ozone, and fine particulate matter (PM2.5). Most of our facilities are located in or near areas that are classified by the EPA as not achieving certain NAAQS (non-attainment areas). The relevant NAAQS have become more stringent and we expect that trend to continue. As a result of such classification and the manner in which regulators seek to achieve the NAAQS, our operations generally are subject to more stringent air pollution requirements than those applicable to facilities located elsewhere. The states are generally free to impose requirements that are more stringent than those imposed by the federal government. We expect increased regulation at both the federal and state levels of our air emissions. We maintain a comprehensive compliance strategy to address these continuing and new requirements. Complying with increasingly stringent NAAQS may require us to install and operate additional emissions control equipment at some of our facilities if we decide to continue to operate such facilities. Such costs could be material. Significant air regulatory programs to which we are subject are described below.

Clean Air Interstate Rule. In 2005, the EPA promulgated the CAIR, which established in the eastern United States SO_2 and NO_x cap-and-trade programs applicable directly to states and indirectly to generating facilities. The NO_x cap-and-trade program has two components, an annual program and an Ozone Season program. The CAIR SO_2 cap-and-trade program builds off the existing acid rain cap-and-trade program but requires generating facilities to surrender twice as many allowances to cover emissions from 2010 through 2014 and approximately three times as many allowances starting in 2015. Florida, Illinois, Maryland, Mississippi, New Jersey, New York, Ohio, Pennsylvania, Texas and Virginia are subject to the CAIR s SO_2 trading program and both its NO_x trading programs. Massachusetts is subject only to the CAIR s Ozone Season NO_x trading program. These cap-and-trade programs were to be implemented in two phases, with the first phase going into effect in 2009 for NO_x and 2010 for SO_2 and more stringent caps going into effect in 2015. Various parties challenged the EPA s adoption of the CAIR, and on July 11, 2008, the D.C. Circuit in *State of North Carolina v. Environmental Protection Agency* issued an opinion that would have vacated the CAIR. Various parties filed requests for rehearing with the D.C. Circuit and on December 23, 2008, the D.C. Circuit issued a second opinion in which it granted rehearing only to the extent that it remanded the case to the EPA without vacating the CAIR. Accordingly, the CAIR will remain effective until it is replaced by a rule consistent with the D.C. Circuit s opinions. The states in which we operate that are subject to CAIR (i.e., Florida, Illinois, Maryland, Massachusetts, Mississippi, New Jersey, New York, Ohio, Pennsylvania, Texas and Virginia) have promulgated regulations implementing the federal CAIR.

The EPA has stated that it expects to finalize the regulations to replace the CAIR in 2011, and on August 2, 2010, the EPA proposed a rule (the Transport Rule) to replace the CAIR. The EPA has sought comment on the proposed Transport Rule as well as several alternatives. If finalized, the CAIR replacement proposal and each of the alternatives would impose more stringent emission reductions than were required under the CAIR. The EPA s proposed replacement rule would establish an emissions budget for each of thirty-one eastern and midwestern states and the District of Columbia, and would allow only limited interstate trading. For SO_2, generating facilities in a region comprised of Georgia, Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and Wisconsin would be subject to a more stringent cap on SO_2 emissions than the other states subject to the rule, and would not be allowed to use emissions allowances from sources in a separate region comprised of Alabama, Connecticut, Delaware, the District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey and South Carolina. For both SO_2 and NO_x, interstate trading of emissions allowances would be allowed only to the extent that the total number of emissions allowances used within a particular state did not exceed the state s budgeted allowances plus a variability limit intended to account for the variability of emissions because of changes in demand for electricity, timing of maintenance activities and unit outages. If total emissions allowances used within a state in a year exceed the annual budget plus the variability limit, then owners of generating facilities in that state that are deemed responsible for the state s exceedance would be required to surrender additional allowances. The two alternatives on which the EPA sought comment would further restrict trading. Under the first alternative, only intrastate trading of allowances would be allowed. The second alternative would establish an emissions limit for each generating facility, with some averaging allowed. In January 2011, the EPA also sought comment on two additional methods of allocating allowances. Finally, the EPA has also stated that it may issue a subsequent, more stringent rule if it concludes that recent or planned revisions to the particulate matter and ozone NAAQS make necessary more stringent limits on SO_2 and NO_x emissions from electric generating facilities. We continue to monitor developments related to the EPA s proposed options to replace the existing CAIR.

The effect on our business of these pending regulations and whether we elect to install additional controls is uncertain and depends on the content and timing of the regulations, the expected effect of the regulations on wholesale power prices and allowance prices, as well as the cost of controls, profitability of our generating facilities, market conditions at the time and the likelihood of CO_2 regulation. We may choose to retire certain of our units rather than install additional controls.

The costs associated with more stringent environmental air quality requirements may result in coal-fired generating facilities, including some of ours, being retired. Although conditions may change, under current and forecasted market conditions, installations of additional scrubbers would not be economic at most of our unscrubbed coal-fired facilities. Any such retirements could contribute to improving supply and demand fundamentals for the remaining fleet. Any resulting increased demand for gas could increase the spread between gas and coal prices, which would also benefit the remaining coal-fired generating facilities.

Maryland Healthy Air Act. The Maryland Healthy Air Act was enacted in April 2006 and requires reductions in SO_2, NO_x and mercury emissions from large coal-fired power facilities. The state law also required Maryland to join the RGGI, which is discussed below. The Maryland Healthy Air Act and the regulations adopted by MDE to implement that act impose limits for (a) emissions of NO_x in 2009 with further reductions in 2012 (including sublimits during the Ozone Season) and (b) emissions of SO_2 in 2010 with further reductions in 2013. The Maryland Healthy Air Act also imposes restrictions on emissions of mercury beginning in 2010 with further reductions in 2013. The Maryland Healthy Air Act imposes fixed limits and owners of power facilities may not exceed these fixed limits by purchasing emissions allowances to comply.

We installed scrubbers at our Chalk Point, Dickerson and Morgantown coal-fired units. In addition, we installed SCR systems at the Morgantown coal-fired units and one of the Chalk Point coal-fired units and a selective auto catalytic reduction system at the other Chalk Point coal-fired unit. We also installed selective non-catalytic reduction systems at the three Dickerson coal-fired units. These controls are capable of reducing emissions of SO_2, NO_x and mercury by approximately 98%, 90% and 80%, respectively, for three of our largest coal-fired units. The control equipment we have installed allows our Maryland generating facilities to comply with (a) the first phase of the CAIR without having to purchase emissions allowances and (b) all of the requirements of the Maryland Healthy Air Act.

In 2009, we had planned outages to complete the installation of the scrubbers. During those outages, we also performed significant maintenance activities. We expect to invest $1.674 billion in capital expenditures to comply with the requirements for SO_2, NO_x and mercury emissions under the Maryland Healthy Air Act. At December 31, 2010, we had invested $1.519 billion of the $1.674 billion. In July 2007, our subsidiaries GenOn Mid-Atlantic and GenOn Chalk Point entered into an agreement with Stone & Webster, Inc. for EPC services relating to the installation of the scrubbers described above. The cost under the agreement was approximately $1.1 billion and is a part of the $1.674 billion described above. See note 18 to our consolidated financial statements under Scrubber Contract Litigation for further discussion.

New Jersey. In April 2009, the New Jersey Department of Environmental Protection finalized a regulation requiring a two-phase reduction in NO_X emissions from combustion turbines in New Jersey. Phase I requires reductions during high electricity demand days and runs from May 2009 through 2014. Under our compliance plan, we operate enhanced NO_x controls at our Shawville, Pennsylvania generating facility (upwind from New Jersey) on high energy demand days. Phase II requires the installation of emission controls on all but one of our New Jersey generating facilities (Gilbert, Glen Gardner, Sayreville and Werner) by May 1, 2015. The New Jersey Department of Environmental Protection is evaluating proposed changes to its high electricity demand days regulations and may defer for two years, in part or in whole, requirements for reduction in NO_x emissions from combustion turbines. If we elect to install these controls, we could incur capital expenditures of up to approximately $190 million primarily during 2014 to 2017 (assuming the two-year deferral described above). Our initial Phase II control plan was filed with the state of New Jersey and our decision on investments should occur by 2012.

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HAPs Regulations. In 2005, the EPA issued the CAMR, which would have limited total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program. In February 2008, the D.C. Circuit vacated the CAMR and the EPA s decision not to regulate coal- and oil-fired electric utility steam generating units under section 112 of the Clean Air Act, which requires the EPA to develop MACT standards for controlling emissions of all HAPs, including mercury. The EPA and a group representing electricity generators sought review of the D.C. Circuit s decision by the United States Supreme Court. In February 2009, the EPA filed to withdraw its petition for review, stating that it intends to promulgate alternative regulations for electricity generators under section 112 of the Clean Air Act, and the United States Supreme Court subsequently denied the petition for review. As a result of the D.C. Circuit decision, coal-fired and oil-fired generating facilities are now subject to regulation under the section of the Clean Air Act that generally requires the EPA to develop MACT standards to control HAPs, including mercury, from each covered facility. Although the EPA has announced that it will develop MACT standards for mercury and other HAPs, it has not yet promulgated such standards. The MACT standards may require us to install and operate additional emissions control equipment at some of our facilities, the cost of which may be material. The EPA has collected emissions data, which will be used to develop such standards. Our Maryland coal-fired units already are subject to mercury limits under the Maryland Healthy Air Act, as described above. Many of our coal-fired units will emit less mercury as a result of the SO_2 and NO_x controls that have been installed. In the interim, a number of states, including Pennsylvania, pursued mercury regulations. In December 2009, the Pennsylvania Supreme Court upheld a lower court s determination that the proposed Pennsylvania mercury rule was unlawful and unenforceable.

New Source Review Enforcement Initiative. The EPA and various states are investigating compliance of coal-fired electric generating facilities with the pre-construction permitting requirements of the Clean Air Act known as new source review. In the past decade, the EPA has made information requests for our Avon Lake, Chalk Point, Cheswick, Conemaugh, Dickerson, Elrama, Keystone, Morgantown, New Castle, Niles, Portland, Potomac River, Shawville and Titus generating facilities. We are corresponding or have corresponded with the EPA regarding all of these requests. If a violation is determined to have occurred at any of the facilities, our subsidiary owning or leasing the facilities may be responsible for the cost of purchasing and installing emissions control equipment, the cost of which may be material. Several of our generating facilities already have installed a variety of emissions control equipment. If such a violation is determined to have occurred after our subsidiaries acquired or leased the facilities or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, our subsidiary owning or leasing the facility at issue could also be subject to fines and penalties by the state or federal government for the period after its acquisition or lease of the facility, the cost of which may be material, although applicable bankruptcy law may bar such liability for the Chalk Point, Dickerson, Morgantown and Potomac River generating facilities for periods prior to January 3, 2006, when the Plan became effective.

Regulation of Greenhouse Gases, including the RGGI. Concern over climate change has led to significant legislative and regulatory efforts at the state and federal level to limit greenhouse gas emissions, especially CO_2. One such effort is the RGGI, a multi-state initiative in the Eastern PJM and Northeast outlining a cap-and-trade program to reduce CO_2 emissions from electric generating units with capacity of 25 MW or greater. The RGGI program calls for signatory states, which include Maryland, Massachusetts, New Jersey and New York, to stabilize CO_2 emissions to an established baseline from 2009 through 2014, followed by a 2.5% reduction each year from 2015 through 2018. Each of these four states has promulgated regulations implementing the RGGI. Complying with the RGGI could have a material adverse effect upon our operations and our operating costs, depending upon the availability and cost of emissions allowances and the extent to which such costs may be offset by higher market prices to recover increases in operating costs caused by the RGGI. As contemplated in a memorandum of understanding among the participating states, Regional Greenhouse Gas Initiative, Inc. is comprehensively reviewing the program, which may cause the participating states to change the manner in which the program is administered and may increase our cost to comply.

During 2010, we produced approximately 17.3 million tons of CO_2 at our Maryland, Massachusetts, New Jersey and New York generating facilities for a total cost of $34 million under the RGGI (including all former Mirant generating facilities for 2010 and all former RRI Energy generating facilities for December 2010). In

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2011, we expect to produce approximately 15.6 million tons of CO_2 at our Maryland, Massachusetts, New Jersey and New York generating facilities. The RGGI regulations required those facilities to obtain allowances to emit CO_2 beginning in 2009. Annual allowances generally were not granted to existing sources of such emissions. Instead, allowances have been made available for such facilities by purchase through periodic auctions conducted quarterly or through subsequent purchase from a party that holds allowances sold through a quarterly auction.

The tenth auction of allowances by the RGGI states was held on December 1, 2010. The clearing price for the approximately 24.8 million allowances sold in the auction allocated for use beginning in the first control period (2009-2011) was $1.86 per ton. The clearing price for the approximately 1.2 million allowances sold in the auction allocated for use beginning in the second control period (2012-2014) was $1.86 per ton. The allowances sold in this auction may be used for compliance in any of the RGGI states. Further auctions will occur quarterly, with the next auction scheduled for March 2011.

In California, emissions of greenhouse gases are governed by California s Global Warming Solutions Act (AB 32), which requires that statewide greenhouse gas emissions be reduced to 1990 levels by 2020. In December 2008, the CARB approved a Scoping Plan for implementing AB 32. The Scoping Plan requires that the CARB adopt a cap-and-trade regulation by January 2011 and that the cap and trade program begin in 2012. The CARB s schedule for developing regulations to implement AB 32 is being coordinated with the schedule of the WCI for development of a regional cap-and-trade program for greenhouse gas emissions. Through the WCI, California is working with other western states and Canadian provinces to coordinate and implement a regional cap-and-trade program. In October 2010, the CARB released its proposed cap-and-trade regulation for public comment, which the CARB approved in December 2010. Our California generating facilities will be required to comply beginning in 2012. The recently adopted cap-and-trade regulation and any other plans, rules and programs approved to implement AB 32, could adversely affect the costs of operating the facilities.

In July 2008, the Pennsylvania Climate Change Act was adopted. This legislation requires development of reports of the effects of climate change in Pennsylvania and potential economic opportunities resulting from mitigation strategies. It requires development of an annual state-level greenhouse gas emissions inventory and baseline, a voluntary registry, and establishment of cost-effective state-level strategies for reducing or offsetting greenhouse gases. The Climate Change Advisory Committee established by the Act published a Climate Change Action Plan in December 2009. The plan includes numerous recommendations to reduce 2020 greenhouse gas emissions in the state by 30 percent below year 2000 levels. Recommendations affecting fossil power generation are carbon capture and sequestration at selected coal-fired units and minimum efficiency improvements. The plans also recommend greenhouse gas performance standards for new power plants.

In August 2008, Massachusetts adopted the Climate Protection Act, which establishes a program to reduce greenhouse gas emissions significantly over the next 40 years. Under the Climate Protection Act, the MADEP has established a reporting and verification system for statewide greenhouse gas emissions, including emissions from generating facilities producing all electricity consumed in Massachusetts, and determined the state s greenhouse gas emissions level in 1990. Under the Climate Change Act, the MAEEA is to establish statewide greenhouse gas emissions limits effective beginning in 2020 that will reduce such emissions from the 1990 levels by a range of 10% to 25% beginning in 2020, with the reduction increasing to 80% below 1990 levels by 2050. In setting these limits, the MAEEA is to consider the potential costs and benefits of various reduction measures, including emissions limits for electric generating facilities, and may consider the use of market-based compliance mechanisms. A violation of the emissions limits established under the Climate Protection Act may result in a civil penalty of up to $25,000 per day. Implementation of the Climate Protection Act could have a material adverse effect on how we operate our Massachusetts generating facilities and the costs of operating those facilities. On December 29, 2010, the MAEEA established a limit for 2020 that is 25% less than the 1990 level.

In April 2009, the Maryland General Assembly passed the Maryland Act, which became effective in October 2009. The Maryland Act requires a reduction in greenhouse gas emissions in Maryland by 25% from 2006 levels by 2020. However, this provision of the Maryland Act is only in effect through 2016 unless a

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subsequent statutory enactment extends its effective period. The Maryland Act requires the MDE to develop a proposed implementation plan to achieve these reductions by the end of 2011 and to adopt a final plan by the end of 2012.

In light of the United States Supreme Court ruling in *Massachusetts v. EPA* that greenhouse gases fit within the Clean Air Act s definition of air pollutant, the EPA has proposed and promulgated regulations regarding the emission of greenhouse gases. In September 2009, the EPA promulgated a rule that requires owners of facilities in many sectors of the economy, including power generation, to report annually to the EPA the quantity and source of greenhouse gas emissions released from those facilities. In addition to this reporting requirement, the EPA has promulgated several rules that address greenhouse gas emissions. In December 2009, under a portion of the Clean Air Act that regulates vehicles, the EPA determined that elevated concentrations of greenhouse gases in the atmosphere endanger the public s health and welfare through their contribution to climate change (Endangerment Finding). In April 2010, the EPA finalized a rule to regulate greenhouse gases from vehicles beginning in model year 2012. In April 2010, the EPA also issued its Reconsideration of Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs, which addresses the scope of pollutants subject to certain permitting requirements under the Clean Air Act as well as when such requirements become effective. The EPA has stated that, because of the vehicle rule, emissions of greenhouse gases from new stationary sources such as power plants and from major modifications to such sources are subject to certain Clean Air Act permitting requirements as of January 2011. These permitting requirements will require such sources to use best available control technology to limit their greenhouse gases. We expect various parties to seek judicial review of these regulations and that the legal challenges to these regulations will not be resolved for several years. The additional substantive requirements under the Clean Air Act that may apply or may come to apply to stationary sources such as power plants are not clear at this time.

In December 2010, the EPA announced that it was starting the process of developing regulations under the New Source Performance Standard section of the Clean Air Act that would affect new and existing fossil-fueled generating facilities. The EPA expects to propose regulations by July 2011 and to finalize such regulations by May 2012.

In addition to the state and regional regulatory matters described above, various bills have been proposed in Congress to govern CO_2 emissions from generating facilities. Current proposals include a cap-and-trade system that would require us to purchase allowances for some or all of the CO_2 emitted by our generating facilities. If CO_2 regulation becomes more stringent, we expect the demand for gas and/or renewable sources of electricity will increase over time. Although we expect that market prices for electricity would increase following such regulation and would allow us to recover a portion of the cost of these allowances, we cannot predict with any certainty the actual increases in costs such regulation could impose upon us or our ability to recover such cost increases through higher market rates for electricity, and such regulation could have a material adverse effect on our consolidated statements of operations, financial position and cash flows. It is possible that Congress will take action to regulate greenhouse gas emissions within the next several years. The form and timing of any final legislation will be influenced by political and economic factors and is uncertain at this time. Implementation of a CO_2 cap-and-trade program in addition to other emission control requirements could increase the likelihood of coal-fired generating facility retirements. During 2010, we produced approximately 20.7 million tons of CO_2 at our generating facilities (including all former Mirant generating facilities for 2010 and all former RRI Energy generating facilities for December 3 to December 31, 2010). Our former RRI Energy generating facilities produced approximately 20.4 million tons of CO_2 for January through December 2, 2010. We expect to produce approximately 40.3 million total tons of CO_2 at our generating facilities in 2011.

Water Regulations

We are required under the Clean Water Act to comply with intake and discharge requirements, requirements for technological controls and operating practices. To discharge water, we generally need permits required by the Clean

Water Act. Such permits typically are subject to review every five years. As with air quality regulations, federal and state water regulations are expected to impose additional and more stringent

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requirements or limitations in the future. This is particularly the case for regulatory requirements governing cooling water intake structures, which are subject to regulation under section 316(b) of the Clean Water Act (the 316(b) regulations). A 2007 decision by the United States Court of Appeals for the Second Circuit (the Second Circuit) in *Riverkeeper Inc. et al. v. EPA*, in which the court remanded to the EPA for reconsideration numerous provisions of the EPA s section 316(b) regulations for existing power plants, has created substantial uncertainty about exactly what technologies or other measures will be needed to satisfy section 316(b) requirements in the future and when any new requirements will be imposed. Following that ruling by the Second Circuit, the EPA in 2007 suspended its 316(b) regulations for existing power plants. Various parties sought review of the Second Circuit s decision by the United States Supreme Court, and it granted those requests with respect to whether the EPA could permissibly weigh costs versus benefits in determining what requirements to impose. On April 1, 2009, the Supreme Court reversed the Second Circuit, ruling that the EPA had permissibly relied on cost-benefit analysis in setting standards for cooling water intake structures for existing power plants and authorizing site-specific variances. The Supreme Court s ruling did not alter other aspects of the Second Circuit s decision. Significant uncertainty remains regarding the effect of the Supreme Court s decision on the EPA s 316(b) regulations for existing power plants and what technologies or other measures will be needed to satisfy section 316(b) regulations. The EPA also is in the process of updating its technology-based regulations regarding discharges from power plants. The EPA has collected information from numerous power plants to inform this rulemaking. The new standards have not yet been proposed. Accordingly, we cannot predict their effect on our business.

At our Shawville, Pennsylvania facility, we could be required to install a cooling tower by late 2013 at one or more of its units in order to comply with our permit. If we decide to install one or more cooling towers, we could invest approximately $160 million, primarily during 2012 to 2014. Under current and forecasted market conditions, such capital expenditures may not be justified. We are continuing to evaluate alternatives and appealing the permit. See discussion below under Shawville NPDES Permit Appeal.

Once-Through Cooling. In October 2010, the California State Water Resources Control Board s (State Water Board s) Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Once-Through Cooling Policy) became effective. Compliance options for our affected generating units include transitioning to a closed-cycle cooling system, retiring, or submitting an alternative plan that meets equivalent mitigation criteria. The specified compliance date for our Pittsburg and Contra Costa generating facilities is December 31, 2017; and for our Mandalay and Ormond Beach generating facilities the date is December 31, 2020. We will shut down the Contra Costa generating facility in April 2013, subject to regulatory approval. We are analyzing compliance options for the remaining affected generating units, and for certain of our California generating facilities the Once-Through Cooling Policy could have a material adverse effect on how we operate those facilities and the costs of operating those facilities. In October 2010, we and several other companies jointly filed a lawsuit in California superior court challenging the State Water Board s issuance of the Once-Through Cooling Policy on various procedural and substantive grounds. The lawsuit seeks a writ directing the State Water Board to vacate and set aside approval of the Once-Through Cooling Policy.

Endangered Species Acts. GenOn Delta s use of water from the Sacramento-San Joaquin Delta at its Contra Costa and Pittsburg generating facilities potentially affects certain fish species protected under the federal Endangered Species Act and the California Endangered Species Act. GenOn Delta therefore must maintain authorization under both statutes to engage in operations that could result in a take of (i.e., cause harm to) fish of the protected species. In January and February 2006, GenOn Delta received correspondence from the United States Fish and Wildlife Service and the U.S. Army Corps of Engineers expressing the view that the federal Endangered Species Act take authorization for the Contra Costa and Pittsburg generating facilities was no longer in effect as a result of changed circumstances. GenOn Delta disagreed with the agencies characterization of its take authorization as no longer being in effect. In October 2007, GenOn Delta received correspondence from the United States Fish and Wildlife Service, the National Marine Fisheries Service and the Army Corps of Engineers clarifying that GenOn Delta continued to be authorized to take four species of fish protected under the federal Endangered Species Act. The agencies have initiated a process that will review the environmental effects of GenOn Delta s water usage, including effects on the protected species of fish. That process could lead to changes in the manner in which GenOn Delta can use river water for the operation of the Contra Costa and Pittsburg generating facilities. As discussed further in note 5(c) to our consolidated financial statements, we plan to shut down the Contra Costa generating facility in April 2013.

By letter dated September 27, 2007, the Coalition for a Sustainable Delta, four water districts, and an individual (the Delta Noticing Parties) provided notice to us of their intent to file suit alleging that GenOn Delta has violated, and continues to violate, the federal Endangered Species Act through the operation of its Contra Costa and Pittsburg generating facilities. The Delta Noticing Parties contend that the facilities use of water drawn from the Sacramento-San Joaquin Delta for cooling purposes results in harm to four species of fish listed as endangered species. The Delta Noticing Parties assert that GenOn Delta s authorizations to take (i.e., cause harm to) those species, a biological opinion and incidental take statement issued by the National Marine Fisheries Service on October 17, 2002, for three of the fish species and a biological opinion and incidental take statement issued by the United States Fish and Wildlife Service on November 4, 2002, for the fourth fish species, have been violated by GenOn Delta and no longer apply to permit the effects on the four fish species caused by the operation of the Contra Costa and Pittsburg generating facilities. Following receipt of these letters, GenOn Delta received in October 2007 the correspondence noted above from the United States Fish and Wildlife Service, the National Marine Fisheries Service and the United States Army Corps of Engineers (the Corps) clarifying GenOn Delta s continuing right to take the four species of fish. In a subsequent letter, the Coalition for a Sustainable Delta also alleged violations of the National Environmental Policy Act and the California Endangered Species Act associated with the operation of GenOn Delta s generating facilities. On May 14, 2009, the Coalition for a Sustainable Delta, Kern County Water Agency and an individual sent a new notice of intent to sue to the Corps alleging that the Corps had violated the federal Endangered Species Act by issuing permits related to the operation of GenOn Delta s Contra Costa and Pittsburg generating facilities without ensuring that conservation measures would be implemented to minimize and mitigate the harm to the four endangered fish species and their habitat allegedly resulting from such operation. GenOn Delta disputes the allegations made by the Delta Noticing Parties and those made in the May 14, 2009 notice.

On February 11, 2010, GenOn Delta entered into a settlement agreement with the Delta Noticing Parties, the parties to the May 14, 2009 notice of intent to sue, and the Corps. The settlement agreement provides for the Delta Noticing Parties and the parties to the May 14, 2009 notice of intent to sue to withdraw the two notices of intent to sue and to release all claims described in those notices. The settlement agreement obligated GenOn Delta to seek approval from the Corps, the United States Fish and Wildlife Service, and the National Marine Fisheries Service to amend its plan then in effect for monitoring entrainment and impingement of aquatic species caused by the operation of its generating facilities to increase monitoring during periods the facilities are operating, and those approvals have been obtained. The settlement agreement requires the Corps to use its best efforts to conclude ongoing consultations with the United States Fish and Wildlife Service and the National Marine Fisheries Service regarding the environmental effects of GenOn Delta s water usage in a timely manner and allows the Delta Noticing Parties and the parties to the May 14, 2009 notice of intent to sue to issue new notices of intent to sue if such consultations are not completed by October 31, 2011.

In November 2009, GenOn Delta signed a second amendment to a Memorandum of Agreement with the California Department of Fish and Game. The amendment requires GenOn Delta to prepare a planning and feasibility study for potential habitat restoration projects and extends by 16 months to March 1, 2011, the deadline for submitting an application for a new permit authorizing GenOn Delta to take the protected fish species affected by the operation of its facilities. The amendment extends GenOn Delta s existing authorization for take of fish species protected under the California Endangered Species Act until the California Department of Fish and Game completes its consideration of the application for the new permit.

Potrero National Pollution Discharge Elimination System Permit. On June 8, 2006, Bayview-Hunters Point Community Advocates and Communities for a Better Environment filed a petition challenging the issuance of the NPDES permit for our Potrero generating facility. On February 8, 2007, Bayview-Hunters Point Community

Advocates and Communities for a Better Environment filed another petition with a request to amend their initial petition. On March 21, 2007, the California State Water Resources Control Board notified the parties that petitioners requested that as of March 19, 2007, the two petitions be moved from active status to abeyance. Those petitions currently remain in abeyance. Additionally, on June 15, 2007, Bayview-Hunters Point Community Advocates and Communities for a Better Environment and San Francisco Baykeeper filed a third petition requesting that the NPDES permits for Potrero and GenOn Delta s Pittsburg generating facility be reopened. The State Water Resources Control Board denied that petition on November 27, 2007. As discussed further in notes 5 and 19 to our consolidated financial statements, the CAISO has determined that the Potrero generating facility is no longer needed for reliability and, accordingly, we shut it down on February 28, 2011.

Kendall NPDES and Surface Water Discharge Permit. On September 26, 2006, the EPA issued to GenOn Kendall an NPDES renewal permit for the Kendall cogeneration facility. The same permit was concurrently issued by the MADEP as a state SWD permit, and was accompanied by MADEP s earlier issued water quality certificate under section 401 of the Clean Water Act. These permits sought to impose new temperature limits at various points in the Charles River, an extensive temperature, water quality and biological monitoring program and a requirement to develop and install a barrier net system to reduce fish impingement and entrainment. The provisions regulating the thermal discharge could have caused substantial curtailments of the operations of the Kendall generating facility. GenOn Kendall appealed the permits in three proceedings: (a) appeal of the NPDES permit to the EPA s Environmental Appeals Board; (b) appeal of the SWD permit to the MADEP; and (c) appeal of the water quality certification to the MADEP. The effect of the permits was stayed pending the outcome of these appeals. On March 6, 2008, the EPA and the MADEP issued a draft permit modification to address the 316(b) provisions of the permit that would have required modifications to the intake structure for the Kendall generating facility to add fine and coarse mesh barrier exclusion technologies and to install a mechanism to sweep organisms away from the intake structure through an induced water flow. On May 1, 2008, GenOn Kendall submitted comments on the draft permit modification objecting to the new requirements. On December 19, 2008, the EPA and the MADEP issued final permit modifications to address the 316(b) regulations. Those final permit modifications did not substantially modify the requirements proposed in the draft modifications, and on February 2, 2009, GenOn Kendall filed an appeal of those modifications.

In October 2010, GenOn Kendall submitted a permit modification request to the EPA and MADEP that requested modification of the 2006 permits (as previously modified in 2008) to reflect revised permit terms agreed upon among GenOn Kendall, the EPA and MADEP as part of a settlement of the permit renewal proceedings pending before EPA and MADEP. The settlement contemplates that an additional steam pipeline will be installed across the Charles River under the Longfellow Bridge to allow GenOn Kendall to make additional steam sales to Trigen-Boston Energy Corporation in Boston and that GenOn Kendall will install a back pressure steam turbine and air cooled condenser at the Kendall generating facility. This new pipeline and equipment once operational, would allow GenOn Kendall to reduce significantly its use of water from the Charles River. On October 25, 2010, EPA and MADEP issued the proposed revised permits (the 2010 Kendall Permits) as draft permit modifications for public comment. On December 17, 2010, the EPA and MADEP issued final permits that became effective on February 1, 2011. The 2010 Kendall Permits will limit GenOn Kendall to drawing no more than 3.2 million gallons of water per day from the river under normal operations, impose temperature limits similar to the 2006 permits, and require monitoring of temperatures at various points in the river when the Kendall generating facility is discharging water to the river. The 2010 Kendall Permits do not require the installation of barrier nets or modifications to the intake structure at the facility. Because river water will no longer be used for once-through cooling under normal operations once the new pipeline and equipment have been installed, GenOn Kendall expects the 2010 Kendall Permits to impose significantly less risk that operations of the facility would have to be curtailed to maintain compliance with the temperature limits. As part of its settlement with the EPA and MADEP, the EPA and MADEP issued administrative orders that defer application of the new limit on the amount of river water used by the Kendall cogenerating facility and the new temperature limits imposed by the 2010 Kendall Permits until installation has been completed of the new pipeline, the back pressure steam turbine, and the air cooled condenser, which is not expected to occur until 2015.

Canal NPDES and SWD Permit. On August 1, 2008, the EPA issued to GenOn Canal an NPDES renewal permit for the Canal generating facility. The same permit was concurrently issued by MADEP as a state SWD Permit, and was accompanied by MADEP s earlier water quality certificate under section 401 of the Clean Water Act. The new permit imposes a requirement on GenOn Canal to install closed cycle cooling or an alternative technology that will reduce the entrainment of marine organisms by the Canal generating facility to levels equivalent to what would be achieved by closed cycle cooling. GenOn Canal appealed the NPDES permit to the EPA s Environmental Appeals Board and appealed the surface water discharge and the water quality certificate to the MADEP. On December 4, 2008, the EPA requested a stay to the appeal proceedings and withdrew provisions related to the closed cycle cooling requirements. The EPA has re-noticed these provisions as draft conditions for additional public comment. GenOn Canal filed comments on January 29, 2009, stating that installing closed cycle cooling at the Canal generating facility was not justified and that without some cost-recovery mechanism the cost would make continued operation of the facility uneconomic. While the appeals of the renewal permit are pending, the effect of any contested permit provisions is stayed and the Canal generating facility will continue to operate under its current NPDES permit. We are unable to predict the outcome of this proceeding.

Conemaugh NPDES Permit. In April 2007, two environmental groups sued GenOn Northeast Management Company in the United States District Court for the Western District of Pennsylvania alleging the inappropriate discharge of five metals to the Conemaugh River from the Conemaugh generating facility. We think that an administrative consent order and agreement signed in 2004 precludes this lawsuit and the two plaintiffs do not have standing. In October 2010, the court denied our motion to dismiss on these two grounds. A trial has been scheduled for June 2011.

Seward NPDES Permit Appeal. The PADEP issued the Seward generating facility a renewed NPDES permit on July 19, 2010. On September 7, 2010, PennEnvironment, Defenders of Wildlife and the Sierra Club challenged this permit. These environmental groups assert that there was insufficient public notice of the final permit. They also assert that PADEP failed to (a) undertake a case-by-case analysis to set technology-based effluent limitations, (b) require sufficient monitoring of temperature changes or a compliance schedule or to otherwise address certain alleged violations, (c) address the discharge of underground seeps to groundwater and (d) properly consider the need for additional water quality-based effluent limitations. We disagree with these allegations and think that all of the issues raised have been adequately and appropriately addressed.

Shawville NPDES Permit Appeal. The PADEP issued the Shawville generating facility a renewed NPDES Permit on August 9, 2010. That permit requires installation of cooling towers or reduction in plant operation by September 1, 2013 to reduce thermal effects on the West Branch of the Susquehanna River, which the Shawville generating facility uses for cooling water. We have appealed the permit because the deadlines for installation of cooling towers are both unachievable and inconsistent with the timeframe for making investment decisions regarding anticipated air quality regulations the Transport Rule, which is expected to replace the CAIR, and the MACT Rule, which is expected to regulate emissions of mercury and other hazardous air pollutants. In addition, the Pennsylvania Fish & Boat Commission appealed the permit, alleging that the schedule for and form of thermal limits on the plant are not sufficiently stringent.

NPDES and State Pollutant Discharge Elimination System Permit Renewals. In addition to the various NPDES proceedings described above, proceedings are currently pending for renewal of the NPDES or state pollutant discharge elimination system permits at many of our generating facilities and ash disposal sites. In general, the EPA and the state agencies responsible for implementing the provisions of the Clean Water Act applicable to the intake of water and discharge of effluent by electric generating facilities have been making the requirements imposed upon such facilities more stringent over time. With respect to each of these permit renewal proceedings, the permit renewal proceeding could take years to resolve and the agency or agencies involved could impose requirements upon the entity owning the facility that require significant capital expenditures, limit the times at which the facility can operate, or increase operations and maintenance costs materially.

Byproducts, Wastes, Hazardous Materials and Contamination

Our facilities are subject to laws and regulations governing waste management. The federal Resource Conservation and Recovery Act of 1976 (and many analogous state laws) contains comprehensive requirements for the handling of solid and hazardous wastes. The generation of electricity produces non-hazardous and hazardous materials, and we incur substantial costs to store and dispose of waste materials. The EPA and the states in which we operate coal-fired units may develop new regulations that impose additional requirements on facilities that store or dispose of materials remaining after the combustion of fossil fuels, including coal ash. If so, we may be required to change our current waste management practices at some facilities and incur additional costs.

In June 2010, the EPA proposed two alternatives for regulating byproducts of coal combustion (e.g., ash and gypsum) under the federal Resource Conservation and Recovery Act of 1976. Under the first proposal, these byproducts would be regulated as solid wastes. Under the second proposal, these byproducts would be regulated as special wastes in a manner similar to the regulation of hazardous waste with an exception for beneficial reuse of these byproducts. The second alternative would impose significantly more stringent requirements on and increase materially the cost of disposal of coal combustion byproducts.

Our Contra Costa, Pittsburg and Potrero generating facilities have areas of soil and groundwater contamination. In 1998, prior to our acquisition of those facilities from PG&E, consultants for PG&E conducted soil and groundwater investigations at those facilities which revealed contamination. The consultants conducting the investigation estimated the aggregate cleanup costs at those facilities could be as much as $60 million. Pursuant to the terms of the Purchase and Sale Agreement with PG&E, PG&E has responsibility for the containment or capping of all soil and groundwater contamination and the disposition of up to 60,000 cubic yards of contaminated soil from the Potrero generating facility and the remediation of any groundwater or solid contamination identified by PG&E s consultants in 1998 at the Contra Costa and Pittsburg generating facilities, before those facilities were purchased in 1999 by our subsidiaries. Pursuant to our requests, PG&E has disposed of 807 cubic yards of contaminated soil from the Potrero generating facility. We are not aware of soil or groundwater conditions at our Contra Costa, Pittsburg and Potrero generating facilities for which we expect remediation costs to be material that are not the responsibility of other parties.

In 2008, we closed and then demolished the Lovett generating facility in New York. Pursuant to an agreement with the New York State Department of Environmental Conservation in 2009, we assessed the environmental condition of the property. We do not yet know what, if any, remediation will be required for the Lovett property.

We are responsible for environmental costs related to site contamination investigations and remediation requirements at four generating facilities in New Jersey. We recorded the estimated long-term liability for the remediation costs of $7 million at December 31, 2010.

Other. As a result of their age, many of our plants contain significant amounts of asbestos insulation, other asbestos containing materials, as well as lead-based paint. We think we properly manage and dispose of such materials in compliance with state and federal rules. See note 5(d) to our consolidated financial statements.

Additionally, CERCLA, also known as the Superfund law, establishes a federal framework for dealing with the cleanup of contaminated sites. Many states have enacted similar state superfund statutes as well as other laws imposing obligations to investigate and clean up contamination. We do not think we have any material liabilities or obligations under CERCLA or similar state laws. These laws impose clean up and restoration liability on owners and operators of plants from or at which there has been a release or threatened release of hazardous substances, together with those who have transported or arranged for the disposal of those substances.

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Employees

At February 11, 2011, we employed 3,487 people, which included approximately 2,621 employees at our generating facilities, 415 employees at our regional offices and 451 employees at our corporate headquarters in Houston, Texas. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
Eastern PJM Region			
IBEW Local 327	New Jersey	17	10/31/2011
IBEW Local 1900(1)	Maryland and Virginia	489	6/1/2015
Western PJM/MISO Region			
IBEW Local 29	Pennsylvania	135	9/30/2014
IBEW Local 459	Pennsylvania	536	5/14/2014
IBEW Local 777	Pennsylvania	130	4/30/2012
UWUA Local 140	Pennsylvania	24	10/31/2013
UWUA Local 270	Avon Lake, Ohio	52	4/30/2013
UWUA Local 270	Niles, Ohio	31	3/31/2014
California			
IBEW Local 47	California	23	3/31/2013
IBEW Local 1245(2)	California	112	10/31/2013
Other Operations			
IBEW Local 66	Texas	12	12/31/2015
IBEW Local 503(3)	New York	30	4/30/2013
UWUA Local 369	Cambridge, Massachusetts	30	2/28/2013
UWUA Local 369(4)	Sandwich, Massachusetts	26	5/31/2011
Total		1,647	

(1) During the second quarter of 2010, we entered into a new collective bargaining agreement with employees represented by IBEW Local 1900. The previous collective bargaining agreement expired on June 1, 2010. As part of the new agreement, we are required to provide additional retirement contributions through the defined contribution plan, increases in pay and other benefits. In addition, the new agreement provides for a change to the postretirement healthcare benefit plan covering Mid-Atlantic union employees to eliminate employer-provided healthcare subsidies through a gradual phase-out.

(2) As a result of the shut down of the Potrero generating facility, we will be downsizing the bargaining unit workforce consistent with an agreement negotiated with Local 1245.

(3) In August 2010, we entered into a new collective bargaining agreement with employees represented by IBEW Local 503. The previous collective bargaining agreement expired on June 1, 2008. After reaching impasse in negotiations with the union, we imposed terms effective January 28, 2009, under which the employees worked without disruption. The new agreement is substantially the same as the imposed contract.

(4) In June 2009, the UWUA Local 480 representing the employees at the Canal generating facility in Sandwich, Massachusetts, merged with the UWUA Local 369. The UWUA Local 369 also represents our employees at the Kendall generating facility in a separate bargaining unit and each facility is covered by its own collective bargaining agreement.

To mitigate and reduce the risk of disruption during labor negotiations, we engage in contingency planning for operation of our generating facilities to the extent possible during an adverse collective action by one or more of our unions.

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Available Information

Our principal offices are at 1000 Main Street, Houston, Texas 77002 (832-357-7000). The following information is available free of charge on our website (http://www.genon.com):

Our corporate governance guidelines and standing board committee charters;

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports; and

Our code of ethics and business conduct.

You can request a free copy of these documents by contacting our investor relations department. It is our intention to disclose amendments to, or waivers from, our code of ethics and business conduct on our website. No information on our website is incorporated by reference into this Form 10-K. In addition, our annual, quarterly and current reports are available on the SEC s website at (http://www.sec.gov) or at its public reference room: 100 F Street, NE, Room 1580, Washington, D.C. 20549 (1-800-SEC-0330).

Item 1A. *Risk Factors.*

We are subject to the following factors that could affect our future performance and results of operations. Also, see Cautionary Statement Regarding Forward-Looking Information on page vii, Business in Item 1 and Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Form 10-K.

Risks Related to the Operation of our Business

The merger that created GenOn may not achieve its intended results, and we may be unable to integrate successfully Mirant s and RRI Energy s operations.

Achieving the anticipated benefits of the merger that created GenOn depends on whether the businesses of RRI Energy and Mirant can be integrated in an efficient and effective manner. Integration of the two companies could take longer than anticipated and could result in the loss of valuable employees, the disruption of our ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect our ability to achieve the anticipated benefits of the merger. We may have difficulty addressing possible differences in corporate cultures and management philosophies. Many of our employees are in new positions following the merger and are required to comply with policies that are new to them, including policies related to risk management. The integration process is subject to a number of uncertainties, and no assurance can be given that the anticipated benefits will be realized or, if realized, the timing of their realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect our future business, financial condition, operating results and prospects.

Our revenues are unpredictable because most of our generating facilities operate without long-term power sales agreements, and our revenues and results of operations depend on market and competitive forces that are beyond our control.

We provide energy, capacity, ancillary and other energy services from our generating facilities into competitive power markets either on a short-term fixed price basis or through power sales agreements. Our revenues from selling capacity are a significant part of our overall revenues. We are not guaranteed recovery of our costs or any return on our capital investments through mandated rates. The market for wholesale electric energy and energy services reflects various market conditions beyond our control, including the balance of supply and demand, our competitors marginal and long-term costs of production, and the effect of market regulation. The price at which we can sell our output may fluctuate on a day-to-day basis, and our ability to transact may be affected by the overall liquidity in the markets in which we operate. These markets remain subject to regulations that limit our ability to raise prices during periods of shortage to the degree that would occur in a fully deregulated market, which may limit our ability to recover costs and an adequate return on our investment. In addition, unlike most other commodities, electric energy can be stored only on a very limited basis and generally must be produced at the time of use. As a result, the wholesale power markets are subject to substantial price fluctuations over relatively short periods of time and can be unpredictable. For further discussion, see Business Competitive Environment. Our revenues and results of operations are influenced by factors that are beyond our control, including:

- the failure of market regulators to develop and maintain efficient mechanisms to compensate merchant generators for the value of providing capacity needed to meet demand;
- actions by regulators, ISOs, RTOs and other bodies that may artificially modify supply and demand levels and prevent capacity and energy prices from rising to the level necessary for recovery of our costs, our investment and an adequate return on our investment;
- legal and political challenges to or changes in the rules used to calculate capacity payments in the markets in which we operate or the establishment of bifurcated markets, incentives, other market design changes or bidding requirements that give preferential treatment to new generating facilities over existing generating facilities or otherwise reduce capacity payments to existing generating facilities;
- the ability of wholesale purchasers of power to make timely payment for energy or capacity, which may be adversely affected by factors such as retail rate caps, refusals by regulators to allow utilities to recover fully their wholesale power costs and investments through rates, catastrophic losses and losses from investments by utilities in unregulated businesses;
- increases in prevailing market prices for fuel oil, coal, natural gas and emissions allowances that may not be reflected in prices we receive for sales of energy;
- increases in electricity supply as a result of actions of our current competitors or new market entrants, including the development of new generating facilities or alternative energy sources that may be able to produce electricity less expensively than our generating facilities and improvements in transmission that allow additional supply to reach our markets;
- increases in credit standards, margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts that are expected, including additional collateral costs associated with OTC hedging activities as a result of OTC regulations adopted pursuant to the Dodd-Frank Act;
- decreases in energy consumption resulting from demand-side management programs such as automated demand response, which may alter the amount and timing of consumer energy use;
- the competitive advantages of certain competitors, including continued operation of older power facilities in strategic locations after recovery of historic capital costs from ratepayers;
- existing or future regulation of our markets by the FERC, ISOs and RTOs, including any price limitations and other mechanisms to address some of the price volatility or illiquidity in these markets or the physical stability of the system;
- regulatory policies of state agencies that affect the willingness of our customers to enter into long-term contracts generally, and contracts for capacity in particular;

changes in the rate of growth in electricity usage as a result of such factors as national and regional economic conditions and implementation of conservation programs;

seasonal variations in energy and natural gas prices, and capacity payments; and

seasonal fluctuations in weather, in particular abnormal weather conditions.

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Some of our existing generating facilities may have a limited life unless we make significant capital expenditures to increase their commercial and environmental performance which may not be justified under current market rules and conditions.

Most of our existing generating facilities in California depend almost entirely on payments in support of system reliability. The energy market, as currently constituted, will not justify the capital expenditures necessary to repower or reconstruct these facilities to make them commercially viable in a merchant market and to meet future environmental requirements. If a commercially reasonable capacity market were to be instituted by the CAISO or we could obtain a contract with a creditworthy buyer, it is possible that we could justify investing the necessary capital to repower or reconstruct these facilities. Absent that, most of our existing generating facilities in California will be commercially viable only as long as they are necessary for reliability. As discussed further in note 5(c) to our consolidated financial statements, we plan to shut down the Contra Costa generating facility in April 2013 and we shut down the Potrero generating facility on February 28, 2011.

Our generating facilities face lower levels of profitability under current and forecasted market conditions and some of our generating facilities may not justify the capital expenditures to make them commercially viable and/or to meet possible environmental requirements.

Changes in the wholesale energy market or in our facility operations could result in impairments.

If our outlook for the wholesale energy market changes negatively, or if our ongoing evaluation of our business results in decisions to mothball, retire or dispose of facilities, we could have impairment charges related to our fixed assets, including the assets of RRI Energy that were recorded at provisional fair values in conjunction with the Merger. These evaluations involve significant judgments about the future. Actual future market prices, project costs and other factors could be materially different from our current estimates. Furthermore, increasing environmental regulatory requirements could result in facilities being removed from service or derated. See Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview in Item 7 of this Form 10-K and note 5 to our consolidated financial statements.

Our Marsh Landing development project is subject to construction risks and, if we are unsuccessful in addressing those risks, we may not recover our investment in the project or our return on the project may be lower than expected.

Under its long-term PPA with PG&E, GenOn Marsh Landing bears the risk of completing the construction of the generating facility by the required completion date under the PPA. GenOn Marsh Landing has posted a letter of credit of $80 million to PG&E to secure its contingent obligations for delay damages or termination payments under the PPA, which amounts were $16 million at December 31, 2010, and escalate over the construction period. GenOn Marsh Landing has also posted a letter of credit and provided a guaranty of GenOn Energy Holdings to the contractor at December 31, 2010 of $26 million and $43 million, respectively, to secure its obligations under the EPC agreement for the Marsh Landing project. GenOn Marsh Landing has also posted surety bonds totaling $4 million to PG&E to secure obligations related to transmission system upgrades and interconnection services. If GenOn Marsh Landing does not complete the construction of the Marsh Landing generating facility by the required completion date under the PPA, our return on the project may be lower than expected. Should the facility fail to be operational by the required date under the PPA or not perform as required under the terms of the PPA, PG&E may have the right to terminate the PPA. As there is currently no wholesale capacity market in California, if PG&E were to terminate the PPA, our return on the project might be materially lower than expected.

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We are exposed to the risk of fuel and fuel transportation cost increases and volatility and interruption in fuel supply because our generating facilities generally do not have long-term agreements for the supply of natural gas, coal and oil and rely on other parties for transportation.

Although we purchase fuel based on our expected fuel requirements, we still face the risks of supply interruptions and fuel price volatility. Our cost of fuel may not reflect changes in energy and fuel prices in part because we must pre-purchase inventories of coal and oil for reliability and dispatch requirements, and thus the price of fuel may have been determined at an earlier date than the price of energy generated from it. The price we can obtain from the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel costs. This may have a material adverse effect on our financial performance. The volatility of fuel prices could adversely affect our financial results and operations.

For our coal-fired generating facilities, we purchase most of our coal from a small number of suppliers under contracts with terms of varying lengths, some of which extend to 2013 and one that extends to 2020. There is risk that our coal suppliers may not provide the contractual quantities on the dates specified within the agreements, or the deliveries may be carried over to future periods. If our coal suppliers do not perform in accordance with the agreements, we may have to procure coal in the market to meet our needs, or power in the market to meet our obligations. In addition, generally our coal suppliers do not have investment grade credit ratings nor do they post collateral with us and, accordingly, we may have limited ability to collect damages in the event of default by such suppliers. Non-performance or default risk by our coal suppliers could have a material adverse effect on our future results of operations, financial condition and cash flows. For a discussion of our coal supplier concentration risk, see note 1 to our consolidated financial statements in this Form 10-K.

For our oil-fired generating facilities, we typically purchase fuel from a limited number of suppliers under contracts with terms of varying lengths. If our oil suppliers do not perform in accordance with the agreements, we may have to procure oil in the market to meet our needs, or power in the market to meet our obligations. For our gas-fired generating facilities, any curtailments or interruptions on transporting pipelines could result in curtailment of our operations or increased fuel supply costs.

Operation of our generating facilities involves risks that may have a material adverse effect on our cash flows and results of operations.

The operation of our generating facilities involves various operating risks, including, but not limited to:

- the output and efficiency levels at which those generating facilities perform;
- interruptions in fuel supply and quality of available fuel;
- disruptions in the delivery of electricity;
- adverse zoning;
- breakdowns or equipment failures (whether a result of age or otherwise);
- violations of our permit requirements or changes in the terms of, or revocation of, permits;
- releases of pollutants and hazardous substances to air, soil, surface water or groundwater;
- ability to transport and dispose of coal ash at reasonable prices;

curtailments or other interruptions in natural gas supply;

shortages of equipment or spare parts;

labor disputes, including strikes, work stoppages and slowdowns;

the aging workforce at certain of our facilities;

operator errors;

curtailment of operations because of transmission constraints;

failures in the electricity transmission system which may cause large energy blackouts;

implementation of unproven technologies in connection with environmental improvements; and

catastrophic events such as fires, explosions, floods, earthquakes, hurricanes or other similar occurrences.

A decrease in, or the elimination of, the revenues generated by our facilities or an increase in the costs of operating them could materially affect our cash flows and results of operations, including cash flows available to us to make payments on our debt or our other obligations.

We are exposed to possible losses that may occur from the failure of a counterparty to perform according to the terms of a contractual arrangement with us, particularly in connection with our non-collateralized power hedges between GenOn Mid-Atlantic and financial institutions.

We are exposed to possible losses from the failure of a counterparty to perform according to the terms of a contractual arrangement with us, particularly in connection with our non-collateralized power hedges between GenOn Mid-Atlantic and financial institutions. Non-collateralized power hedges represent 42% of our net notional power position at December 31, 2010. Such hedges are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties, and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. Deterioration in the financial condition of our counterparties and any resulting failure to pay amounts owed to us or to perform obligations or services owed to us beyond collateral posted could have a negative effect on our business and financial condition.

We are subject to adverse developments in the regions in which we operate, especially the PJM market.

At December 31, 2010, our generating capacity was 50% in PJM, 23% in CAISO, 10% in the Southeast, 7% in MISO and 10% in NYISO and ISO-NE. Adverse developments in these regions, especially in the PJM market (where most of our revenues are derived), may adversely affect our results of operations or financial condition. The effect of such adverse regional developments may be greater on us than on our more diversified competitors.

Our income tax NOL carry forwards could be substantially limited if we experience an ownership change as defined in the IRC.

We have approximately $1.9 billion of federal NOL carry forwards, which we are able to use to offset taxable income in future years. If, however, an ownership change, as defined in IRC Section (IRC §) 382, occurs, the amount of NOLs that could be used in any one year following such ownership change would be substantially limited. In general, an ownership change would occur when there is a greater than 50-percentage point increase in ownership of a company s stock by stockholders each of which owns (or is deemed to own under IRC § 382) 5% or more of such company s stock. Given IRC § 382 s broad definition, an ownership change could be the unintended consequence of otherwise normal market trading in our stock that is outside our control. Moreover, while we have a stockholder rights plan in place in an effort to preserve our NOLs, the stockholder rights plan can only deter, not prevent, an ownership change that would result in the loss of our NOLs. See notes 7 and 13 to our consolidated financial statements.

Competition in wholesale power markets may have a material adverse effect on our financial condition, results of operations and cash flows.

We compete with non-utility generators, regulated utilities, and other energy service companies in the sale of our products and services, as well as in the procurement of fuel and transmission services. We compete primarily on the basis of price and service. Regulated utilities in the wholesale markets generally enjoy a lower cost of capital than we do and often are able to recover fixed costs through regulated retail rates, including, in many cases, the costs of generation, allowing them to build, buy and upgrade generating facilities without relying exclusively on market-clearing prices to recover their investments. The competitive advantages of such participants could adversely affect our ability to compete effectively and could have an adverse effect on the revenues generated by our facilities.

Changes in technology may significantly affect our generating business by making our generating facilities less competitive.

We generate electricity using fossil fuels at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in those technologies, or governmental incentives for renewable energies, will reduce their costs to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

The expected decommissioning and/or site remediation obligations of certain of our generating facilities may negatively affect our cash flows.

Some of our generating facilities and related properties are subject to decommissioning and/or site remediation obligations that may require material expenditures. Furthermore, laws and regulations may change to impose material additional decommissioning and remediation obligations on us in the future. If we are required to make material expenditures to decommission or remediate one or more of our facilities, such obligations will affect our cash flows and may adversely affect our ability to make payments on our obligations.

Terrorist attacks, future wars or risk of war may adversely affect our results of operations, our ability to raise capital or our future growth.

As a power generator, we face heightened risk of an act of terrorism, either a direct act against one of our generating facilities or an act against the transmission and distribution infrastructure that is used to transport our power, which would cause an inability to operate as a result of systemic damage. Further, we rely on information technology networks and systems to operate our generating facilities, engage in asset management activities, and process, transmit and store electronic information. Security breaches of this information technology infrastructure, including cyber-attacks and cyber terrorism, could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information. If such an attack or security breach were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, such an attack could affect our ability to service our indebtedness, our ability to raise capital and our future growth opportunities.

Our operations are subject to hazards customary to the power generating industry. We may not have adequate insurance to cover all of these hazards.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of high-speed rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks (such as earthquake, flood, storm surge, lightning, hurricane, tornado and wind), hazards (such as fire, explosion, collapse and machinery failure) are inherent risks in our operations. These hazards can cause significant injury to personnel or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot assure that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A hazard or liability for which we are not fully insured could have a material adverse effect on our financial results and our financial condition.

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Lawsuits, regulatory proceedings and tax proceedings could adversely affect our future financial results.

From time to time, we are named as a party to, or our property is the subject of, lawsuits, regulatory proceedings or tax proceedings. We are currently involved in various proceedings which involve highly subjective matters with complex factual and legal questions. Their outcome is uncertain. Any claim that is successfully asserted against us could require significant expenditures by us and could have a material adverse effect on our results of operations. Even if we prevail, any proceedings could be costly and time-consuming, could divert the attention of our management and key personnel from our business operations and could result in adverse changes in our insurance costs, which could adversely affect our financial condition, results of operations or cash flows. See notes 7, 18 and 19 to our consolidated financial statements.

If we acquire or develop additional facilities, dispose of existing facilities or combine with other businesses, we may incur additional costs and risks.

We may seek to purchase or develop additional facilities, dispose of existing facilities, or combine with other businesses. There is no assurance that these efforts will be successful. In addition, these activities involve risks and challenges, including identifying suitable opportunities, obtaining required regulatory and other approvals, integrating acquired or combined operations with our own, and increasing expenses and working capital requirements. Furthermore, in any sale, we may be required to indemnify a purchaser against liabilities. To finance future acquisitions, we may be required to issue additional equity securities or incur additional debt. Obtaining such additional financing is dependent on numerous factors, including general economic and capital market conditions, credit availability from financial institutions, the covenants in our debt agreements, and our financial performance, cash flow and credit ratings. We cannot make any assurances that we would be able to obtain such additional financing on commercially reasonable terms or at all.

Risks Related to Economic and Financial Market Conditions

The failure of the lenders under our undrawn credit facilities to perform could have a material adverse effect on our liquidity and results of operations. We are exposed to systemic risk of the financial markets and institutions and the risk of non-performance of the individual lenders under our undrawn credit facilities.

Maintaining sufficient liquidity in our business for maintenance and operating expenditures, capital expenditures and collateral is crucial in order to mitigate the risk of future financial distress to us. Accordingly, we maintain a revolving credit facility to manage our expected liquidity needs and contingencies as described in more detail in this Form 10-K. The failure of our lenders to perform under our revolving credit facility could have a material adverse effect on our results of operations. In the event that financial institutions are unwilling or unable to renew our existing revolving credit facility or enter into new revolving credit facilities, our ability to hedge economically our assets or engage in proprietary trading could also be impaired. A significant portion of the Marsh Landing project costs are expected to be funded through drawings under the GenOn Marsh Landing credit facility. The failure of the lenders to perform under that credit facility and related interest rate swaps could have a material adverse effect on the ability to complete construction of the Marsh Landing facility or on the expected return on that investment.

As financial institutions consolidate and operate under more restrictive capital constraints and regulations, there could be less liquidity in the energy and commodity markets, which could have a negative effect on our ability to hedge economically and transact with creditworthy counterparties.

We hedge economically a substantial portion of our Eastern PJM coal-fired baseload generation and certain of our other generation. A significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral, either for initial margin or for securing exposure as a result of changes in power or natural gas prices. In recent years, global financial institutions have been active participants in these energy and commodity markets. As such financial institutions consolidate and operate under more restrictive capital constraints and regulations, there could be less liquidity in the energy and

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commodity markets, which could have a negative effect on our ability to hedge economically and transact with creditworthy counterparties.

The Dodd-Frank Act could materially affect our business, including greater regulation of energy contracts and OTC derivative financial instruments, which could materially affect our ability to hedge economically our generation.

The Dodd-Frank Act, which was enacted in July 2010 in response to the global financial crisis, increases the regulation of transactions involving OTC derivative financial instruments. The statute provides that standardized swap transactions between dealers and large market participants will have to be cleared and traded on an exchange or electronic platform. Although the provisions and legislative history of the Dodd-Frank Act provide strong evidence that market participants, such as the Company, which utilize OTC derivative financial instruments to hedge commercial risks are not to be subject to these clearing and exchange-trading requirements, it is uncertain what the final implementing regulations to be issued by the CFTC and SEC will provide. The effect of the Dodd-Frank Act on our business depends in large measure on pending CFTC and SEC rulemaking proceedings and, in particular, the final definitions for the key terms Swap Dealer and Major Swap Participant in the Dodd-Frank Act. The CFTC and SEC issued a proposed rulemaking to set final definitions for the terms Swap Dealer and Major Swap Participant, among others. Entities defined as Swap Dealers and Major Swap Participants will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. As proposed, the Swap Dealer definition in particular is ambiguous, subjective and could be broad enough to encompass some energy companies. If applied to our hedging activity, such regulations could materially affect our ability to hedge economically our generation by reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with such activities.

Changes in commodity prices may negatively affect our financial results by increasing the cost of producing power or lowering the price at which we are able to sell our power.

Our generating business is subject to changes in power prices and fuel and emissions costs, and these commodity prices are influenced by many factors outside our control, including weather, seasonal variation in supply and demand, market liquidity, transmission and transportation inefficiencies, availability of competitively priced alternative energy sources, demand for energy commodities, production of natural gas, coal and crude oil, natural disasters, wars, embargoes and other catastrophic events, and federal, state and environmental regulation and legislation. In addition, significant fluctuations in the price of natural gas may cause significant fluctuations in the price of electricity. Significant fluctuations in commodity prices may affect our financial results and financial position by increasing the cost of producing power and decreasing the amounts we receive from the sale of power.

Our asset management activities will not fully protect us from fluctuations in commodity prices.

We engage in asset management activities related to sales of electricity and purchases of fuel. The income and losses from these activities are recorded as operating revenues and fuel costs. We may use forward contracts and other derivative financial instruments to manage market risk and exposure to volatility in prices of electricity, coal, natural gas, emissions and oil. We cannot provide assurance that these strategies will be successful in managing our price risks, or that they will not result in net losses to us as a result of future volatility in electricity, fuel and emissions markets. Actual power prices and fuel costs may differ from our expectations.

Our asset management activities include natural gas derivative financial instruments that we use to hedge economically power prices for our baseload generation. The effectiveness of these hedges is dependent upon the correlation between power and natural gas prices in the markets where we operate. If those prices are not sufficiently correlated, our financial results and financial position could be adversely affected. See note 4 to our consolidated financial statements and Quantitative and Qualitative Disclosures About Market Risk in Item 7A of this Form 10-K.

Additionally, we expect to have an open position in the market, within our established guidelines, resulting from our proprietary trading and fuel oil management activities. To the extent open positions exist, fluctuating commodity prices can affect our financial results and financial position, either favorably or unfavorably. As a result of these and other factors, we cannot predict the outcome that risk management decisions may have on our business, operating results or financial position. Although management devotes considerable attention to these issues, their outcome is uncertain.

Our policies and procedures cannot eliminate the risks associated with our hedging and proprietary trading activity.

The risk management procedures we have in place may not always be followed or may not always work as planned. If any of our employees were able to violate our system of internal controls, including our risk management policy, and engage in unauthorized hedging and related activities, it could result in significant penalties and financial losses. In addition, risk management tools and metrics such as value at risk, gross margin at risk, and stress testing are partially based on historic price movements. If price movements significantly or persistently deviate from historical behavior, risk limits may not fully protect us from significant losses.

The accounting treatment of our asset management, proprietary trading and fuel oil management activities may increase the volatility of our quarterly and annual financial results.

We engage in asset management activities to hedge economically our exposure to market risk with respect to: (a) electricity sales from our generating facilities, (b) fuel used by those facilities and (c) emissions allowances. We generally attempt to balance our fixed-price purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative financial instruments. We also use derivative financial instruments with respect to our limited proprietary trading and fuel oil management activities, through which we attempt to achieve incremental returns by transacting where we have specific market expertise. Derivatives from our asset management, proprietary trading and fuel oil management activities are recorded on our balance sheet at fair value pursuant to the accounting guidance for derivative financial instruments. Other than interest rate swaps into which we entered to manage our interest rate risk associated with our GenOn Marsh Landing project financing, which were designated as cash flow hedges, none of our other derivatives recorded at fair value is designated as a hedge under this guidance, and changes in their fair values currently are recognized in earnings as unrealized gains or losses. As a result, our GAAP financial results including gross margin, operating income and balance sheet ratios will, at times, be volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices. See note 4 to our consolidated financial statements.

Risks Related to Governmental Regulation and Laws

Our costs of compliance with environmental laws are significant and can affect our future operations and financial results.

We are subject to extensive and evolving environmental regulations, particularly in regard to our coal- and oil-fired facilities. Failure to comply with environmental requirements could require us to shut down or reduce production at our facilities or create liabilities. We incur significant costs in complying with these regulations and, if we fail to comply, could incur significant penalties. Our cost estimates for environmental compliance are based on existing regulations or our view of reasonably likely regulations, and our assessment of the costs of labor and materials and the state of evolving technologies. Our decision to make these investments is often subject to future market conditions. Changes to the preceding factors, new or revised environmental regulations, litigation and new legislation and/or regulations, as well as other factors, could cause our actual costs to vary outside the range of our estimates, further constrain our operations, increase our environmental compliance costs and/or make it uneconomical to operate some of our facilities. Environmental laws, particularly with respect to air emissions, disposal of ash, wastewater discharge and cooling water systems, are generally becoming more stringent, which may require us to make additional facility upgrades or restrict our operations.

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We are required to surrender emission allowances equal to emissions of specific substances to operate our facilities. Surrender requirements may require purchase of allowances, which may be unavailable or only available at costs that would make it uneconomical to operate our facilities.

Federal, state and regional initiatives to regulate greenhouse gas emissions could have a material impact on our financial performance and condition. The actual impact will depend on a number of factors, including the overall level of greenhouse gas reductions required under any such regulations, the final form of the regulations or legislation, and the price and availability of emission allowances if allowances are a part of the final regulatory framework. See Business Environmental Matters in Item 1, Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview in Item 7 of this Form 10-K and note 18 to our consolidated financial statements.

Certain environmental laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws, impose strict and, in many circumstances, joint and several liability for costs of remediating contamination. Some of our facilities have areas with known soil and/or groundwater contamination. Releases of hazardous substances at our generating facilities, or at locations where we dispose of (or in the past disposed of) hazardous substances and other waste, could require us to spend significant sums to remediate contamination, regardless of whether we caused such contamination. The discovery of significant contamination at our generating facilities, at disposal sites we currently use or have used, or at other locations for which we may be liable, or the failure or inability of parties contractually responsible to us for contamination to respond when claims or obligations regarding such contamination arise, could have a material adverse effect on our financial performance and condition.

Our coal-fired generating units produce certain byproducts that involve extensive handling and disposal costs and are subject to government regulation. Changes in these regulations, or their administration, by legislatures, state and federal regulatory agencies, or other bodies may affect the costs of handling and disposing of these byproducts.

As a result of the coal combustion process, we produce significant quantities of ash at our coal-fired generating units that must be disposed of at sites permitted to handle ash. For most of our ash disposal, we use our own ash management facilities, which are all dry landfills to dispose of the ash; however, one of our landfills in Maryland has reached design capacity and we expect that another one of our sites in Maryland may reach full capacity in the next few years. As a result, we have a plan to develop new ash management facilities and also commenced construction in February 2011 of a facility that is designed to prepare our ash from certain of our Maryland facilities for beneficial uses. However, the costs associated with purchasing new land and permitting the land to allow for ash disposal could be material, and the amount of time needed to obtain permits for the land could extend beyond the expected timeline. Likewise, the ongoing construction of a facility to prepare our ash for beneficial use may be delayed, cost more than expected or not operate as expected; or the ash may not be marketed and sold as expected. Additionally, costs associated with third-party ash handling and disposal are material and could have an adverse effect on our financial performance and condition.

We also produce gypsum as a byproduct of the SO_2 scrubbing process at our coal-fired generating facilities, which is sold to third parties for use in drywall production. Should our ability to sell such gypsum to third parties be restricted as a result of the lack of demand or otherwise, our gypsum disposal costs could rise materially.

The EPA has proposed two alternatives for regulating byproducts such as ash and gypsum. One of these alternatives would regulate these byproducts as special wastes in a manner similar to the regulation of hazardous wastes. If these byproducts are regulated as special wastes, the cost of disposing of these byproducts would increase materially and may limit our ability to recycle them for beneficial use. The EPA expects to finalize this rule in late 2011.

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Our business is subject to complex government regulations. Changes in these regulations, or their administration, by legislatures, state and federal regulatory agencies, or other bodies may affect the prices at which we are able to sell the electricity we produce, the costs of operating our generating facilities or our ability to operate our facilities.

We are subject to regulation by the FERC regarding the rates, terms and conditions of wholesale sales of electric capacity, energy and ancillary services and other matters, including mergers and acquisitions, the disposition of facilities under the FERC s jurisdiction and the issuance of securities, as well as by state agencies regarding physical aspects of our generating facilities. The majority of our generation is sold at market prices under market-based rate authority granted by the FERC. If certain conditions are not met, the FERC has the authority to withhold or rescind market-based rate authority and require sales to be made based on cost-of-service rates. A loss of our market-based rate authority could have a materially negative impact on our generating business.

Even when market-based rate authority has been granted, the FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, when it determines that potential market power might exist and that the public interest requires such potential market power to be mitigated. In addition to direct regulation by the FERC, most of our facilities are subject to rules and terms of participation imposed and administered by various ISOs and RTOs. Although these entities are themselves ultimately regulated by the FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, ISOs and RTOs may impose bidding and scheduling rules, both to curb the potential exercise of market power and to ensure market functions. Such actions may materially affect our ability to sell and the price we receive for our energy, capacity and ancillary services.

To conduct our business, we must obtain and periodically renew licenses, permits and approvals for our facilities. These licenses, permits and approvals can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain and comply with all necessary licenses, permits and approvals for these facilities. If we cannot comply with all applicable regulations, our business, results of operations and financial condition could be adversely affected.

We cannot predict whether the federal or state legislatures will adopt legislation relating to the restructuring of the energy industry. There are proposals in many jurisdictions that would either roll back or advance the movement toward competitive markets for the supply of electricity, at both the wholesale and retail levels. In addition, any future legislation favoring large, vertically integrated utilities and a concentration of ownership of such utilities could affect our ability to compete successfully, and our business and results of operations could be adversely affected. Similarly, any regulations or laws that favor new generation over existing generation could adversely affect our business and results of operations.

Risks Related to Level of Indebtedness

Our substantial indebtedness and operating lease obligations could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and prevent us from meeting or refinancing our obligations.

We have a substantial amount of indebtedness. At December 31, 2010, our consolidated indebtedness was $6.1 billion. In addition, the present values of lease payments under the respective GenOn Mid-Atlantic and REMA operating leases were approximately $927 million and $488 million, respectively (assuming a 10% and 9.4% discount rate, respectively) and the termination value of the respective GenOn Mid-Atlantic and REMA operating leases was $1.4 billion and $752 million.

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Our substantial indebtedness and operating lease obligations could have important consequences for our liquidity, results of operations, financial position and prospects, including our ability to grow in accordance with our strategy. These consequences include the following:

- they may limit our ability to obtain additional debt or equity financing for working capital, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes;
- a substantial portion of our cash flows from operations must be dedicated to the payment of rent and principal and interest on our indebtedness and will not be available for other purposes, including our working capital, capital expenditures, acquisitions and other general corporate purposes;
- the debt service requirements of our indebtedness could make it difficult for us to satisfy or refinance our financial obligations;
- certain of our borrowings, including borrowings under our senior secured credit facility, are at variable rates of interest, exposing us to the risk of increased interest rates;
- they may limit our flexibility in planning for and reacting to changes in our industry;
- they may place us at a competitive disadvantage compared to other, less leveraged competitors;
- our new credit facilities contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interest; and
- we may be more vulnerable in a downturn in general economic conditions or in our business and we may be unable to carry out capital expenditures that are important to our long-term growth or necessary to comply with environmental regulations.

GenOn and its subsidiaries that are holding companies, including GenOn Americas Generation, may not have access to sufficient cash to meet their obligations if their subsidiaries, in particular GenOn Mid-Atlantic, are unable to make distributions.

We and certain of our subsidiaries, including GenOn Americas Generation, are holding companies and, as a result, are dependent upon dividends, distributions and other payments from our operating subsidiaries to generate the funds necessary to meet our obligations. In particular, a substantial portion of the cash from our operations is generated by GenOn Mid-Atlantic. The ability of certain of our subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At December 31, 2010, GenOn Mid-Atlantic and REMA satisfied the respective restricted payments tests.

We may be unable to generate sufficient cash to service our debt and to post required amounts of cash collateral necessary to hedge economically market risk.

Our ability to pay principal and interest on our debt depends on our future operating performance. If our cash flows and capital resources are insufficient to allow us to make scheduled payments on our debt, we may have to reduce or delay capital expenditures, sell assets, seek additional capital, restructure or refinance. There can be no assurance that the terms of our debt will allow these alternative measures, that the financial markets will be available to us on acceptable terms or that such measures would satisfy our scheduled debt service obligations. If we do not comply with the payment and other material covenants under our debt agreements, we could be required to repay our debt immediately and, in the case of our revolving credit facilities, the commitment to lend us money could terminate.

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We seek to manage the risks associated with the volatility in the price at which we sell power produced by our generating facilities and in the prices of fuel, emissions allowances and other inputs required to produce such power by entering into hedging transactions. These asset management activities may require us to post collateral either in the form of cash or letters of credit. At December 31, 2010, we had approximately $265 million of posted cash collateral and $267 million of letters of credit outstanding under our revolving credit facility primarily to support our asset management activities, trading activities, rent reserve requirements and other commercial arrangements. See note 6 to our consolidated financial statements for further information on our posted cash collateral and letters of credit. Although we seek to structure transactions in a way that reduces our potential liquidity needs for collateral, we may be unable to execute our hedging strategy successfully if we are unable to post the amount of collateral required to enter into and support hedging contracts.

We are an active participant in energy exchange and clearing markets. These markets require a per-contract initial margin to be posted, regardless of the credit quality of the participant. The initial margins are determined by the exchanges through the use of proprietary models that rely on a variety of inputs and factors, including market conditions. We have limited notice of any changes to the margin rates. Consequently, we are exposed to changes in the per unit margin rates required by the exchanges and could be required to post additional collateral on short notice.

The terms of our credit facilities restrict our current and future operations, particularly our ability to respond to changes or take certain actions.

Our credit facilities contain a number of restrictive covenants that impose significant operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long-term best interest, including restrictions on our ability to:

- incur additional indebtedness;
- pay dividends or make other distributions or repurchase or redeem capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- sell assets;
- incur liens;
- enter into transactions with affiliates;
- enter into sale-leaseback transactions; and
- consolidate, merge or sell all or substantially all of our assets.

In addition, the restrictive covenants in our credit facilities require us to maintain a ratio of consolidated secured debt (net of up to $500 million in cash) to EBITDA of not more than 3.50 to 1.00, which will be tested at the end of each fiscal quarter and, in the case of EBITDA, will be calculated on a rolling four fiscal quarter basis ending on the last day of such fiscal quarter. Our ability to meet that financial ratio can be affected by events beyond our control. Our failure to comply with the covenants in our credit facilities could result in an event of default under our credit facilities and any other debt to which a cross-default or cross-acceleration provision applies.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Our generating facilities are described under Business Business Segments in Item 1 of this Form 10-K. We own or lease oil and gas pipelines that serve our generating facilities. Our principal executive offices at

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1000 Main Street, Houston, Texas 77002 are leased through 2018, subject to two five-year renewal options. We also lease offices, including a trading floor, at 1155 Perimeter Center West, Suite 100, Atlanta, GA 30338 and various other office spaces. We think that our properties are adequate for our present needs. Except for the Conemaugh, Keystone and Sabine facilities, our interest at December 31, 2010 is 100% for each property. We have satisfactory title, rights and possession to our owned facilities, subject to exceptions, which, in our opinion, would not have a material adverse effect on the use or value of the facilities.

Item 3. *Legal Proceedings.*

See note 18 to our consolidated financial statements for discussion of the material legal proceedings to which we are a party.

Item 4. *Removed and Reserved by the SEC.*

PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

The common stock data included in this Item 5 refers to GenOn s common stock from December 3, 2010 through December 31, 2010 and to RRI Energy, Inc. s common stock (ticker symbol RRI) for all other periods presented.

Common Stock. Our common stock trades on the NYSE under the ticker symbol GEN. On February 18, 2011, we had 88,158 stockholders of record. The closing price of our common stock on December 31, 2010 was $3.81. We have never paid dividends. Some of our debt agreements restrict the payment of dividends. See note 6 to our consolidated financial statements.

We are authorized to issue 2 billion shares of common stock having a par value of $.001 per share and 125 million shares of preferred stock having a par value of $.001 per share. In addition, we reserved shares for unresolved claims related to the Mirant bankruptcy, of which approximately 1.3 million shares had not yet been distributed at December 31, 2010.

The following table sets forth the high and low prices for our common stock as reported by the NYSE for the periods indicated.

	Market Price	
	High	**Low**
2010:		
First Quarter	$ 6.21	$ 3.57
Second Quarter	$ 4.91	$ 3.50
Third Quarter	$ 4.30	$ 3.35
Fourth Quarter	$ 4.04	$ 3.46
2009:		
First Quarter	$ 7.38	$ 2.03
Second Quarter	$ 6.23	$ 3.03
Third Quarter	$ 7.64	$ 4.44
Fourth Quarter	$ 7.21	$ 4.76

Securities Authorized for Issuance under Equity Compensation Plans. See Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information related to securities authorized for issuance under equity compensation plans.

Stock Performance Graph. The performance graph below is being provided as furnished and not filed, as permitted by 17 Code of Federal Regulations 229.201(e), in this Form 10-K and compares the cumulative total stockholder return on our common stock (GenOn or RRI Energy) with the Standard & Poor s 500 Index and a group of our peer companies in our industry comprised of Allegheny Energy, Inc., Calpine Corporation, Constellation Energy Group, Inc., Dynegy Inc., Mirant, NRG Energy, Inc. and PPL Corporation. In 2010, we added Constellation Energy Group, Inc. to our peer group of companies because of the Merger. The graph assumes that $100 was invested on December 31, 2005, in our common stock (GenOn or RRI Energy) and each of the above indices (except that Calpine

Corporation is only included in the peer group since its emergence from bankruptcy in January 2008 and Mirant is only included since its emergence from bankruptcy in January 2006 through the Merger close on December 3, 2010) and that all dividends were reinvested.

GenOn Energy, Inc

Company Name/Index	Indexed Returns 2005	2006	2007	2008	2009	2010
GenOn	100.00	137.69	254.26	56.01	55.43	35.93
S&P 500	100.00	115.79	122.16	76.96	97.33	111.99
2009 Peer Group(1)	100.00	130.50	180.12	94.65	96.59	89.12
2010 Peer Group(2)	100.00	128.35	181.41	83.82	90.67	83.41

(1) The 2009 Peer Group consists of Allegheny Energy, Inc. (AYE), PPL Corporation (PPL), Calpine Corporation (CPN), Dynegy Inc. (DYN), Mirant Corporation (MIR) and NRG Energy, Inc. (NRG).

(2) The 2010 Peer Group consists of Allegheny Energy, Inc. (AYE), PPL Corporation (PPL), Calpine Corporation (CPN), Dynegy Inc. (DYN), Mirant Corporation (MIR), NRG Energy, Inc. (NRG) and Constellation Energy Group, Inc. (CEG).

Source: SNL Financial LC, Charlottesville, VA

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Item 6. *Selected Financial Data.*

The following discussion should be read in conjunction with our consolidated financial statements and the notes thereto, which are in this Form 10-K. The following tables present our selected consolidated financial information, which is derived from our consolidated financial statements.

Upon completion of the Merger, Mirant stockholders had a majority of the voting interest in the combined company. Although RRI Energy issued shares of RRI Energy common stock to Mirant stockholders to effect the Merger, the Merger is accounted for as a reverse acquisition under the acquisition method of accounting. Under the acquisition method of accounting, Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the consolidated financial statements and results below of GenOn include the results of Mirant, from January 1, 2006 through December 2, 2010, and include the results of the combined entities for the period from December 3, 2010 through December 31, 2010. The EPS data has been retroactively adjusted to give effect to the Exchange Ratio. The consolidated financial statements presented herein for periods ended prior to the closing of the Merger (and any other financial information presented herein with respect to such pre-merger dates, unless otherwise specified) are the consolidated financial statements and other financial information of Mirant.

	2010	2009	2008	2007	2006
		(in millions, except per share data)			
Statements of Operations Data:					
Operating revenues	$ 2,270	$ 2,309	$ 3,188	$ 2,019	$ 3,087
Income (loss) from continuing operations	(50)	494	1,215	433	1,752
Net income (loss)	(50)	494	1,265	1,995	1,864
Basic EPS per common share from continuing operations	$ (0.11)	$ 1.20	$ 2.31	$ 0.61	$ 2.17
Diluted EPS per common share from continuing operations	$ (0.11)	$ 1.20	$ 2.15	$ 0.55	$ 2.08

Our Statement of Operations Data for each year reflects the volatility caused by unrealized gains and losses related to derivative financial instruments used to hedge economically electricity and fuel. Changes in the fair value and settlements of derivative financial instruments used to hedge economically electricity are reflected in operating revenue and changes in the fair value and settlements of derivative financial instruments used to hedge economically fuel are reflected in cost of fuel, electricity and other products in the consolidated statements of operations. Changes in the fair value and settlements of derivative financial instruments for proprietary trading and fuel oil management activities are recorded on a net basis as operating revenue in the consolidated statements of operations. See note 4 to our consolidated financial statements.

	2010	2009	2008	2007	2006
			(In millions)		
Unrealized gains (losses) included in operating revenues	$ 45	$ (2)	$ 840	$ (564)	$ 757
Unrealized (gains) losses included in cost of fuel, electricity and other products	87	(49)	54	(28)	102
Total	$ (42)	$ 47	$ 786	$ (536)	$ 655

For 2010, net loss reflects the following before taxes:

$565 million of impairment losses related to our Dickerson and Potomac River generating facilities. See note 5(c) to our consolidated financial statements for further information on these impairments.

$518 million gain on bargain purchase, $114 million of merger-related costs and $24 million related to the accelerated vesting of Mirant s stock-based compensation as a result of the Merger. See notes 2 and 3 to our consolidated financial statements for further information on the Merger and restructuring charges; and

$9 million in write-off of unamortized debt issuance costs. See note 6 to our consolidated financial statements for further information on the debt transactions.

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For 2009, net income reflects the following before taxes:

$221 million of impairment losses related to our Potomac River generating facility and intangible assets related to our Potrero and Contra Costa generating facilities. See note 5(c) to our consolidated financial statements for further information on these impairments.

For 2007, net income reflects the following before taxes:

$175 million impairment loss related to our Lovett generating facility;

$379 million gain related to the settlement of litigation with Pepco; and

$2.0 billion gain on sale of our Philippine business, $63 million gain on sale of our Caribbean business and $38 million gain on sale of certain U.S. generating facilities, all recorded in discontinued operations.

For 2006, net income reflects the following before taxes:

$120 million impairment loss related to suspended construction at our Bowline generating facility; and

$244 million gain from a New York property tax settlement.

The consolidated Balance Sheet Data at December 31, 2006 segregates pre-petition liabilities subject to compromise from those liabilities that were not subject to compromise.

	December 31,				
	2010	2009	2008	2007	2006
	(in millions)				
Balance Sheet Data:					
Total assets	$ 15,274	$ 9,528	$ 10,688	$ 10,538	$ 12,845
Current portion of long-term debt	2,058	75	46	142	142
Long-term debt, net of current portion	4,023	2,556	2,630	2,953	3,133
Liabilities subject to compromise					18
Stockholders equity	5,630	4,315	3,762	5,310	4,443

The amounts for 2010 reflect the assets acquired and the debt transactions entered into related to the Merger. For additional information on the Merger and related debt transactions, see notes 2 and 6 to our consolidated financial statements.

In 2010, we reclassified the principal balance of the GenOn Americas Generation senior notes due in May 2011 from long-term debt to current portion of long-term debt.

On January 1, 2010, we adopted revised accounting guidance related to accounting for variable interest entities. As a result, MC Asset Recovery, LLC was deconsolidated from our financial results. The total assets at December 31, 2009 in the table above have been adjusted from amounts previously presented to reflect a $39 million reduction as a result of the deconsolidation of MC Asset Recovery, LLC. The adoption of this accounting guidance did not affect any of the other periods presented. For additional information, see note 15 to our consolidated financial statements.

In 2005, we recorded the effects of the Plan. As a result, liabilities subject to compromise at December 31, 2006, only reflect the liabilities of our New York entities that remained in bankruptcy at that time. Total assets for all periods reflect our election in 2008 to discontinue the net presentation of assets subject to master netting agreements upon adoption of the accounting guidance for offsetting amounts related to certain contracts.

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

This section is intended to provide the reader with information that will assist in understanding our financial statements, the changes in those financial statements from year to year and the primary factors contributing to those changes. The following discussion should be read in conjunction with our consolidated financial statements and the notes accompanying those financial statements.

Merger of Mirant and RRI Energy

On December 3, 2010, Mirant and RRI Energy completed their Merger. Mirant merged with a wholly-owned subsidiary of RRI Energy, with Mirant surviving the Merger as a wholly-owned subsidiary of RRI Energy. In connection with the all-stock, tax-free Merger, RRI Energy changed its name to GenOn Energy, Inc., Mirant stockholders received a fixed ratio of 2.835 shares of GenOn common stock for each share of Mirant common stock, and Mirant changed its name to GenOn Energy Holdings.

Although RRI Energy was the legal acquirer, the Merger was accounted for as a reverse acquisition, and Mirant was deemed to have acquired RRI Energy for accounting purposes. As a consequence of the reverse acquisition accounting treatment, the historical financial statements presented for periods prior to the Merger date are the historical statements of Mirant, except for stockholders equity which has been retroactively adjusted for the equivalent number of shares of the legal acquirer. The operations of the former RRI Energy businesses have been included in the financial statements from the date of the Merger. For a discussion of our strategy, see Item 1, Business Strategy in this Form 10-K.

Our Business

With approximately 24,200 MW of electric generating capacity, we operate across various fuel (natural gas, coal and oil) and technology types, operating characteristics and regional power markets. At December 31, 2010, our generating capacity was 50% in PJM, 23% in CAISO, 10% in the Southeast, 7% in MISO and 10% in NYISO and ISO-NE.

We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States, including ISOs and RTOs, power aggregators, retail providers, electric-cooperative utilities, other power generating companies and load serving entities. Our commercial operations consist primarily of dispatching electricity, hedging the generation and sale of electricity, procuring and managing fuel and providing logistical support for the operation of our facilities (e.g., by procuring transportation for coal and natural gas), as well as our proprietary trading operations.

We typically sell the electricity we produce into the wholesale market at prices in effect at the time we produce it (spot price). We use dispatch models to assist in making daily bidding decisions regarding the quantity and price of the power we offer to generate from our facilities and sell into the markets. We bid the energy from our generating facilities into the hour-ahead or day-ahead energy market and sell ancillary services through the ISO and RTO markets. We work with the ISOs and RTOs in real time to ensure that our generating facilities are dispatched economically to meet the reliability needs of the market.

Spot prices for electricity are volatile, as are prices for fuel and emissions allowances. In order to reduce the risk of price volatility and achieve more predictable financial results, we have historically entered into economic hedges forward sales of electricity and forward purchases of fuel and emissions allowances to permit us to produce and sell the electricity to manage the risks associated with such volatility. In addition, given the high correlation between natural gas prices and electricity prices in the markets in which we operate, we have entered into forward sales of natural gas to hedge economically exposure to changes in the price of electricity. We procure hedges in OTC transactions or on exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with buyers and sellers, using futures, forwards, swaps and options.

We sell capacity either bilaterally or through periodic auctions in each ISO and RTO market in which we participate. These capacity sales provide an important source of predictable revenues for us over the contracted period. At January 31, 2011, total projected contracted capacity and PPA revenues for which prices have been set for 2011 through 2014 are $3.1 billion.

In addition to the activities described above, we buy and sell some electricity, fuel and emissions allowances, sometimes through financial derivatives, as part of our proprietary trading, fuel oil management and natural gas transportation and storage activities. We engage in proprietary trading to gain information about the markets in which we operate to support our asset management and to take advantage of selected opportunities that we identify. We enter into fuel oil management activities to hedge economically the fair value of our physical fuel oil inventories, optimize the approximately three million barrels of storage capacity that we own or lease, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products. We engage in natural gas transportation and storage activities to optimize our physical natural gas and storage positions and manage the physical gas requirements for a portion of our assets. Proprietary trading, fuel oil management and natural gas transportation and storage activities together will typically comprise less than 5% of our realized gross margin. All of our commercial activities are governed by a comprehensive risk management policy, which includes limits on the size of volumetric positions and VaR for our proprietary trading and fuel oil management activities. For 2010, the combined average daily VaR for proprietary trading and fuel oil management activities was $2 million.

Hedging Activities

We hedge economically a substantial portion of our Eastern PJM coal-fired baseload generation and certain of our other generation. We generally do not hedge our intermediate and peaking units for tenors greater than 12 months. We hedge economically using products which we expect to be effective to mitigate the price risk of our generation. However, as a result of market liquidity limitations, our hedges often are not an exact match for the generation being hedged, and, we then have some risks resulting from price differentials for different delivery points and for implied differences in heat rates when we hedge economically power using natural gas. Currently, a significant portion of our hedges are financial swap transactions between GenOn Mid-Atlantic and financial counterparties that are senior unsecured obligations of such parties and do not require either party to post cash collateral either for initial margin or for securing exposure as a result of changes in power or natural gas prices. At January 31, 2011, our aggregate hedge levels based on expected generation for each year were as follows:

	2011[(1)]	**2012**	**2013**	**2014**	**2015**
Power	72%	33%	14%	13%	%
Fuel	87%	38%	27%	7%	7%

(1) Percentages represent the period from February through December 2011.

See Item 1A, Risk Factors Risks Related to Economic and Financial Market Conditions for a discussion of:

- the risks of consolidation of financial institutions and more restrictive capital constraints and regulation, which could have a negative effect on our ability to hedge economically with creditworthy counterparties; and

- the risks of implementation of the Dodd-Frank Act on our ability to hedge economically our generation, including potentially reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with such activities.

Capital Expenditures and Capital Resources

For 2010, we invested $298 million for capital expenditures, excluding capitalized interest, of which $114 million related to compliance with the Maryland Healthy Air Act. At December 31, 2010, we have invested $1.519 billion of the $1.674 billion that was budgeted for capital expenditures related to compliance with the Maryland Healthy Air Act. As the final part of our compliance with the Maryland Healthy Air Act, we placed four scrubbers in service at our Maryland facilities in the fourth quarter of 2009. Provisions in the construction contracts for the scrubbers provide for certain payments to be made after final completion of the project. The current budget of $1.674 billion continues to represent our best estimate of the total capital expenditures for compliance with the Maryland Healthy Air Act. See note 18 to our consolidated financial statements for further discussion of scrubber contract litigation.

For 2010, our capitalized interest was $6 million compared to $72 million for 2009. The decrease in capitalized interest from 2009 is a result of placing our scrubbers in service at our Maryland facilities in the fourth quarter of 2009.

The following table details the expected timing of payments for our estimated capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for 2011 and 2012:

	2011	**2012**
	(in millions)	
Maryland Healthy Air Act	$ 155	$
Other environmental	39	46
Maintenance	111	79
Marsh Landing generating facility	218	292
Other construction	52	4
Other	17	11
Total	$ 592	$ 432

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures. However, we plan to fund a substantial portion of the capital expenditures for the Marsh Landing generating facility with approximately $500 million of project financing debt into which we entered on October 8, 2010. See California Development Activities below for additional information on the Marsh Landing generating facility. Other environmental capital expenditures set forth above could significantly increase subject to the content and timing of final rules and future market conditions.

Environmental Matters

We make decisions to invest capital for environmental controls based on relatively certain regulations and the expected economic returns on the capital. As discussed in Part 1 of this Form 10-K under Business Regulatory Environment Environmental Regulation, the effect on our business of pending EPA regulations to replace the CAIR and whether we elect to install additional controls are uncertain and depend on the content and timing of the regulations, the expected effect of the regulations on wholesale power prices and allowance prices, as well as the cost of controls, profitability of our generating facilities, market conditions at the time and the likelihood of CO_2 regulation. The EPA has stated that it expects to finalize the regulations to replace the CAIR in 2011. We may choose to retire certain of our units rather than install additional controls.

The costs associated with more stringent environmental air quality requirements may result in coal-fired generating facilities, including some of ours, being retired. Although conditions may change, under current and forecasted market conditions, installations of additional scrubbers would not be economic at most of our unscrubbed coal-fired facilities. Any such retirements could contribute to improving supply and demand fundamentals for the remaining fleet. Any resulting increased demand for gas could increase the spread between gas and coal prices, which would also benefit the remaining coal-fired generating facilities.

Furthermore, federal, state-specific or regional regulatory initiatives to stimulate CO_2 emission reductions in our industry are being considered. The effect on our business of these matters is uncertain and depends on the form and content of resulting regulations, if any, including their effect on (a) wholesale electricity and emissions allowance prices and (b) other existing regulations such as the RGGI.

If CO_2 regulation becomes more stringent, we expect that the demand for gas and/or renewable sources of electricity will increase over time. Although we expect that market prices for electricity would increase following such regulation and would allow us to recover a portion of the resulting costs, we cannot predict with any certainty the actual increases in costs such regulation could impose upon us or our ability to recover such cost increases through higher market rates for electricity. It is possible that Congress will take action to regulate greenhouse gas emissions within the next several years. The form and timing of any final legislation will be influenced by political and economic factors and are uncertain at this time. Implementation of a CO_2 cap-and-trade program in addition to other emission control requirements could increase the likelihood of coal-fired generating facility retirements.

Given the uncertainty related to these environmental matters, we cannot predict their actual outcome or ultimate effect on our business, and such matters could result in a material adverse effect on our results of operations, financial position and cash flows. See Business Regulatory Environment Environmental Regulation and Risk Factors Risks Related to Governmental Regulation and Laws in Items 1 and 1A, respectively, of this Form 10-K and note 18 to our consolidated financial statements for further discussion.

Commodity Prices

The prices for power and natural gas remain low compared to several years ago. The energy gross margin from our generating facilities is negatively affected by these price levels. For that portion of the volumes of generation that we have hedged, we are generally economically neutral to subsequent changes in commodity prices because our realized gross margin will reflect the contractual prices of our power and fuel contracts. We continue to add economic hedges, including to maintain projected levels of cash flows from operations for future periods to help support continued compliance with the covenants in our debt and lease agreements.

California Development Activities

GenOn Marsh Landing

On September 2, 2009, GenOn Marsh Landing entered into a ten-year PPA with PG&E for 760 MW of natural gas-fired peaking generation to be constructed adjacent to our Contra Costa generating facility near Antioch, California.

During the ten-year term of the PPA, GenOn Marsh Landing will receive fixed monthly capacity payments and variable operating payments. The contract provides PG&E with the entire output of the 760 MW generating facility, which is expected to be capable of producing 719 MW during peak July conditions.

On May 6, 2010, GenOn Marsh Landing entered into an EPC agreement with Kiewit Power Constructors Co. (Kiewit) for the construction of the Marsh Landing generating facility. Under the EPC agreement, Kiewit is to design and construct the Marsh Landing generating facility on a turnkey basis, including all engineering, procurement, construction, commissioning, training, start-up and testing. The lump sum cost of the EPC agreement is $499 million (including the $212 million total cost under the Siemens Turbine Generator Supply and Services Agreement which was assigned to Kiewit in connection with the execution of the EPC agreement), plus the reimbursement of California sales and use taxes. See Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations in Liquidity and Capital Resources for additional information on the EPC agreement with Kiewit.

On October 8, 2010, GenOn Marsh Landing entered into a credit agreement for up to $650 million of commitments to finance the Marsh Landing generating facility. See note 6 to our consolidated financial statements for further discussion.

GenOn Marsh Landing has received all permits necessary to begin construction and, on October 8, 2010, directed Kiewit to commence engineering and procurement for the Marsh Landing generating facility. Construction of the

Marsh Landing generating facility is expected to be completed by mid-2013.

Contra Costa Toll Extension

On September 2, 2009, GenOn Delta entered into an agreement with PG&E for the 674 MW of Contra Costa units 6 and 7 for the period from November 2011 through April 2013. At the end of the agreement, and subject to any necessary regulatory approval, GenOn Delta has agreed to retire Contra Costa units 6 and 7, which began operations in 1964, in furtherance of state and federal policies to retire aging power plants that utilize once-through cooling technology.

Pittsburg Toll Extension

On October 28, 2010, GenOn Delta entered into an agreement with PG&E for 1,159 MW of capacity from Pittsburg units 5, 6 and 7 for three years commencing January 1, 2011, with options for PG&E to extend the agreement for each of 2014 and 2015. Under the agreement, GenOn Delta will receive monthly capacity payments with bonuses and/or penalties based on heat rate and availability.

Potrero Settlement

On August 13, 2009, GenOn Potrero entered into a settlement agreement (Potrero Settlement) with the City and County of San Francisco. Among other things, the Potrero Settlement obligates GenOn Potrero to close permanently each of the remaining units of the Potrero generating facility at the end of the year in which the CAISO determines that such unit is no longer needed to maintain the reliable operation of the electricity system. In December 2010, the CAISO provided GenOn Potrero with the requisite notice of termination of the RMR agreement. On January 19, 2011, at the request of GenOn Potrero, the FERC approved changes to GenOn Potrero s RMR agreement to allow the CAISO to terminate the RMR agreement effective February 28, 2011. On February 28, 2011, the Potrero facility was shut down. See note 19 to our consolidated financial statements for further discussion of the Potrero Settlement.

IBEW Local 1900 Collective Bargaining Agreement

During the second quarter of 2010, we entered into a new collective bargaining agreement with our employees represented by IBEW Local 1900 (located in Maryland and Virginia). The previous collective bargaining agreement expired on June 1, 2010. The new agreement has a five-year term expiring on June 1, 2015. As part of the new agreement, we are required to provide additional retirement contributions through the defined contribution plan, increases in pay and other benefits. In addition, the agreement provides for a change to the postretirement healthcare benefit plan covering IBEW Local 1900 union employees to eliminate employer-provided healthcare subsidies through a gradual phase-out. We recorded the effects of the plan curtailment during the second quarter of 2010 and recognized a reduction in other postretirement liabilities of $48 million and a decrease in accumulated other comprehensive loss of $11 million on the consolidated balance sheet and a gain of $37 million reflected as a reduction in operations and maintenance expense on the consolidated statement of operations. In addition, we recognized an increase of $3 million in our pension liability and in accumulated other comprehensive loss as a result of planned salary increases under the new collective bargaining agreement. See note 8 to our consolidated financial statements for additional information on the postretirement healthcare benefit curtailment.

Results of Operations

Upon completion of the Merger, Mirant stockholders had a majority of the voting interest in the combined company. Although RRI Energy issued shares of RRI Energy common stock to Mirant stockholders to effect the Merger, the Merger is accounted for as a reverse acquisition under the acquisition method of accounting. Under the acquisition method of accounting, Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the consolidated financial statements and results below of GenOn include the results of Mirant, from January 1, 2008 through December 2, 2010, and include the results of the combined entities for the period from December 3, 2010 through December 31, 2010. The consolidated financial statements presented herein for periods ended prior to the closing of the Merger (and any other financial information presented herein with respect to such pre-merger dates, unless otherwise specified) are the consolidated financial statements and other financial information of Mirant.

Non-GAAP Performance Measures. The following discussion includes the non-GAAP financial measures realized gross margin and unrealized gross margin to reflect how we manage our business. In our discussion of the results of our reportable segments, we include the components of realized gross margin, which are energy, contracted and capacity, and realized value of hedges. Management generally evaluates our operating results excluding the impact of unrealized gains and losses. When viewed with our GAAP financial results, these non-GAAP financial measures may provide a more complete understanding of factors and trends affecting our business. Realized gross margin represents our gross margin (excluding depreciation and amortization) less unrealized gains and losses on derivative financial instruments. Conversely, unrealized gross margin represents our unrealized gains and losses on derivative financial instruments. None of our derivative financial instruments recorded at fair value is designated as a hedge (other than our interest rate swaps) and changes in their fair values are recognized currently in income as unrealized gains or losses. As a result, our financial results are, at times, volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices. Realized gross margin, together with its components energy, contracted and capacity, and realized value of hedges, provide a measure of performance that eliminates the volatility reflected in unrealized gross margin, which is created by significant shifts in market values between periods. We also disclose the non-GAAP financial measures adjusted income from continuing operations and adjusted EBITDA as consolidated performance measures, which exclude unrealized gross margin. As mentioned above, management generally evaluates our operating results excluding the effect of unrealized gains and losses. Adjusted income from continuing operations and adjusted EBITDA also exclude items related to the Merger and the former Mirant bankruptcy, as well as impairment charges and net lower of cost or market adjustments to our commodity inventories and certain other items. We adjust for the subsequent benefit created by commodity inventory utilized in operations that were subject to prior period lower of cost or market adjustments. We exclude or adjust for these items to provide a more meaningful representation of our ongoing results of operations. However, these non-GAAP financial measures may not be comparable to similarly titled non-GAAP financial measures used by other companies.

We use these non-GAAP financial measures in communications with investors, analysts, rating agencies, banks and other parties. Adjusted EBITDA is a key performance metric in our employee short-term incentive structure for annual bonuses. We think these non-GAAP financial measures provide meaningful representations of our consolidated operating performance and are useful to us and others in facilitating the analysis of our results of operations from one period to another. We view adjusted EBITDA as providing a measure of operating results unaffected by differences in capital structures, capital investment cycles and ages of related assets among otherwise comparable companies. We encourage our investors to review our consolidated financial statements and other publicly filed reports in their entirety and not to rely on a single financial measure.

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2010 Compared to 2009

Consolidated Financial Performance

We reported net loss of $50 million and net income of $494 million for 2010 and 2009, respectively. The change in net income/loss is detailed as follows:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Realized gross margin	$ 1,349	$ 1,552	$ (203)
Unrealized gross margin	(42)	47	(89)
Total gross margin (excluding depreciation and amortization)	1,307	1,599	(292)
Operating expenses:			
Operations and maintenance	846	609	237
Depreciation and amortization	224	149	75
Impairment losses	565	221	344
Gain on sales of assets, net	(4)	(22)	18
Total operating expenses, net	1,631	957	674
Operating income (loss)	(324)	642	(966)
Other expense (income), net:			
Gain on bargain purchase	(518)		(518)
Interest expense, net	253	135	118
Equity in income of affiliates		1	(1)
Other, net	(7)		(7)
Total other expense (income), net	(272)	136	(408)
Income (loss) before income taxes	(52)	506	(558)
Provision (benefit) for income taxes	(2)	12	(14)
Net income (loss)	$ (50)	$ 494	$ (544)

Realized Gross Margin. For 2010, our realized gross margin decrease of $203 million was principally a result of the following:

- a decrease of $336 million in realized value of hedges. In 2010 and 2009, realized value of hedges was $293 million and $629 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, offset in part by the amount by which contract prices for fuel exceeded market prices for fuel; partially offset by

- an increase of $113 million in energy, primarily as a result of an increase in energy in Eastern PJM because of an increase in the average settlement price for power, a decrease in the cost of emissions allowances, higher generation volumes and the addition of the Western PJM/MISO segment in 2010, offset in part by a decrease in realized gross margin from proprietary trading and fuel oil management activities in Energy Marketing and an increase in the average price of fuel; and

an increase of $20 million in contracted and capacity primarily as a result of the addition of the Western PJM/MISO segment in 2010 as a result of the Merger, an increase in ancillary services revenue and additional megawatts of capacity sold in Eastern PJM, offset in part by a decrease in capacity prices in Eastern PJM.

Unrealized Gross Margin. Our unrealized gross margin for both periods reflects the following:

unrealized losses of $42 million in 2010, which included $389 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period,

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substantially offset by a $347 million net increase in the value of hedge and proprietary trading contracts for future periods. The increase in value was primarily related to decreases in forward power and natural gas prices offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010; and

unrealized gains of $47 million in 2009, which included a $686 million net increase in the value of hedge and trading contracts for future periods primarily related to decreases in forward power and natural gas prices, substantially offset by $639 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses. Our operating expenses increase of $674 million was primarily a result of the following:

an increase of $344 million in impairment losses. In 2010, we recognized $565 million in impairment losses related to our Dickerson and Potomac River generating facilities. In 2009, we recognized $221 million in impairment losses related to our Potomac River generating facility and intangible assets related to our Potrero and Contra Costa generating facilities. See note 5(c) to our consolidated financial statements for additional information related to our impairment reviews;

an increase of $237 million in operations and maintenance expense primarily related to the following:

an increase of $114 million in merger-related costs incurred in 2010, which included $67 million of advisory and legal costs and $35 million related to severance;

an increase of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, comprised of a $52 million reduction in operations and maintenance expense for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed, and a $10 million reversal of accruals for future funding to MC Asset Recovery. See note 18 to our consolidated financial statements for additional information related to the settlement between MC Asset Recovery and Southern Company;

an increase of $45 million related to the addition of the Western PJM/MISO segment as a result of the Merger;

an increase of $32 million related to the recognition of a liability associated with our commitment to reduce particulate emissions at our Potomac River generating facility as a part of the agreement with the City of Alexandria, Virginia because the planned capital investment would not be recovered in future periods based on the current projected cash flows for the Potomac River generating facility and the full impairment of the facility in 2010. See note 5(c) to our consolidated financial statements for additional information related to our impairment reviews;

an increase of $29 million primarily as a result of an increase in costs related to the operation of the scrubbers at our Maryland generating facilities and the Montgomery County, Maryland CO_2 levy imposed on our Dickerson generating facility beginning in May 2010, offset in part by a decrease in planned maintenance costs in 2010 compared to 2009; and

an increase of $24 million related to the accelerated vesting of Mirant s stock-based compensation as a result of the Merger; partially offset by a decrease of $37 million as a result of a curtailment gain recorded during the second quarter of 2010 resulting from an amendment to our postretirement healthcare benefits plan covering Eastern PJM union employees. See note 8 to our consolidated financial statements for additional information related to the postretirement healthcare benefit curtailment;

a decrease of $20 million primarily related to lower property taxes because of a lower assessed value for the Lovett generating facility which was demolished in 2009 and a decrease in shutdown costs associated with this generating facility; and a decrease of $12 million related to severance and stock-based compensation costs not related to the Merger primarily as a result of the departure of certain executives in 2009;

an increase of $75 million in depreciation and amortization expense primarily as a result of the scrubbers at our Maryland generating facilities that were placed in service in December 2009 and the addition of the long-lived assets acquired in the Merger; and

a decrease of $18 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Gain on Bargain Purchase. We reported a gain on bargain purchase of $518 million during 2010. Because the fair value of the net assets acquired in the Merger exceeds the purchase price, the Merger is being accounted for as a bargain purchase in accordance with acquisition accounting guidance. The estimated gain on the bargain purchase is primarily a result of differences between the long-term fundamental value of the generating facilities and the effect of the near-term view of the equity markets on the price of Mirant common stock at the close of the Merger, specifically as a result of the following:

current dark spreads (the difference between the price received for electricity generated compared to the market price of the coal required to produce the electricity) have decreased significantly in recent years as a result of natural gas prices that are lower compared to historical levels and increased coal prices that are affected by international demand;

uncertainty related to the nature and timing of environmental regulation, including carbon legislation; and

certain generating facilities owned by RRI Energy prior to the Merger being located in markets experiencing lower demand for electricity as a result of economic conditions but forecasted to have long-term declining reserve margins.

The Merger is accounted for under the acquisition method of accounting for business combinations. Accordingly, we conducted an assessment of the net assets acquired and recognized provisional amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition are expensed as incurred. Any changes to the fair value assessments will affect the gain on bargain purchase and material changes could require the financial statements to be retroactively amended. See note 2 to our consolidated financial statements for additional information related to the Merger.

Interest Expense, Net. Interest expense, net increase of $118 million was primarily a result of the following:

$66 million increase primarily resulting from higher interest expense as a result of lower capitalized interest because of the scrubbers at our Maryland generating facilities that were placed in service in December 2009; and

$47 million increase related to interest incurred on our senior notes and credit facilities and interest expense on debt assumed in the Merger.

Other, Net. Other, net change of $7 million was primarily a result of the following:

$14 million of other income, recognized in accordance with accounting guidance, relating to the reimbursement of pre-merger interest paid by RRI Energy on GenOn s debt in accordance with the pre-merger escrow arrangements; partially offset by

$9 million of other expense relating to the write-off of unamortized debt issuance costs related to the GenOn North America senior secured term loan that was repaid in 2010.

Adjusted EBITDA and Adjusted Income from Continuing Operations. The following table reconciles the non-GAAP consolidated performance measures adjusted income from continuing operations and adjusted

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EBITDA to net income/loss. See discussion above regarding changes in net income/loss, including the significant items excluded or adjusted in arriving at the non-GAAP measures in the following table.

	2010	2009
	(in millions)	
Net Income (loss)	$ (50)	$ 494
Impairment losses	565	221
Merger-related costs	114	
Unrealized (gains) losses	42	(47)
Potomac River settlement obligation	32	
Mirant s accelerated vesting of stock-based compensation	24	
Loss on early extinguishment of debt	9	
Lower of cost or market inventory adjustments, net	(4)	(31)
Reimbursement of pre-merger expenses from RRI Energy	(14)	
Post-retirement benefit curtailment gain	(37)	
Gain on bargain purchase	(518)	
Bankruptcy charges and legal contingencies		(62)
Severance and bonus plan for dispositions		13
Lovett shut down costs		5
Other		1
Adjusted income from continuing operations	163	594
Depreciation and amortization	224	149
Interest expense, net	253	135
Provision (benefit) for income tax	(2)	12
Adjusted EBITDA	$ 638	$ 890

Segments

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. We previously had four reportable segments: Mid-Atlantic, Northeast, California and Other Operations. In the fourth quarter of 2010, in conjunction with the Merger, we began reporting in five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. We reclassified amounts for 2009 and 2008 to conform to the current segment presentation.

In the tables below, for 2010, the Eastern PJM segment consists of eight generating facilities located in Maryland, New Jersey and Virginia. The Western PJM/MISO segment consists of 23 generating facilities located in Illinois, Ohio and Pennsylvania. The California segment consists of eight generating facilities located in California. The California segment also includes business development efforts for new generation in California, including GenOn Marsh Landing. The Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations consists of nine generating facilities located in Massachusetts, New York, Florida, Mississippi and Texas. Other Operations also includes unallocated overhead expenses and other activity that cannot be specifically identified to another

segment. In the following tables, eliminations are primarily related to intercompany sales of emissions allowances.

Gross Margin Overview

The following tables detail realized and unrealized gross margin for 2010 and 2009, by operating segments:

	2010						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
				(in millions)			
Energy	$ 384	$ 33	$	$ 34	$ 19	$	$ 470
Contracted and capacity	341	32	126		87		586
Realized value of hedges	280				13		293
Total realized gross margin	1,005	65	126	34	119		1,349
Unrealized gross margin	7	(22)		(8)	(19)		(42)
Total gross margin(1)	$ 1,012	$ 43	$ 126	$ 26	$ 100	$	$ 1,307

	2009						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
				(in millions)			
Energy	$ 170	$	$	$ 167	$ 23	$ (3)	$ 357
Contracted and capacity	351		122		93		566
Realized value of hedges	586				43		629
Total realized gross margin	1,107		122	167	159	(3)	1,552
Unrealized gross margin	144			(113)	16		47
Total gross margin(1)	$ 1,251	$	$ 122	$ 54	$ 175	$ (3)	$ 1,599

(1) Gross margin excludes depreciation and amortization.

Energy represents gross margin from the generation of electricity, fuel sales and purchases at market prices, fuel handling, steam sales and our proprietary trading and fuel oil management activities, and natural gas transportation and storage activities.

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts (for 2010 and 2009), through PPAs and tolling agreements and from ancillary services.

Realized value of hedges represents the actual margin upon the settlement of our power and fuel hedging contracts and the difference between market prices and contract costs for fuel. Power hedging contracts include sales of both power and natural gas used to hedge power prices as well as hedges to capture the incremental value related to the geographic location of our physical assets.

Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

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Operating Statistics

The following table summarizes net capacity factor by segment for 2010 and 2009:

	2010	2009	Increase/ (Decrease)
Eastern PJM	33%	30%	3%
Western PJM/MISO	36%	N/A	N/A
California	2%	5%	(3)%
Energy Marketing	N/A	N/A	N/A
Other Operations	8%	10%	(2)%
Total	20%	19%	1%

The following table summarizes power generation volumes by segment for 2010 and 2009:

	2010	2009	Increase/ (Decrease)	Increase/ (Decrease)
	(in gigawatt hours)			
Eastern PJM:				
Baseload	14,271	13,500	771	6%
Intermediate	1,120	363	757	209%
Peaking	219	92	127	138%
Total Eastern PJM	15,610	13,955	1,655	12%
Western PJM/MISO:				
Baseload	1,743		1,743	N/A
Intermediate	375		375	N/A
Peaking	2		2	N/A
Total Western PJM/MISO	2,120		2,120	N/A
California:				
Intermediate	530	1,050	(520)	(50)%
Peaking[1]	(1)	4	(5)	(125)%
Total California	529	1,054	(525)	(50)%
Other Operations:				
Baseload	1,485	1,425	60	4%
Intermediate	395	673	(278)	(41)%
Peaking	22	3	19	633%
Total Other Operations	1,902	2,101	(199)	(9)%

Total	20,161	17,110	3,051	18%

(1) Negative amounts denote net energy used by the generating facility.

The total increase in power generation volumes for 2010, as compared to 2009, is primarily the result of the following:

Eastern PJM. An increase in our generation volumes primarily as a result of higher power prices resulting from an increase in demand because of higher average temperatures and a decrease in outages in 2010 compared to 2009.

Western PJM/MISO. The Western PJM/MISO segment was formed as a result of the Merger.

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California. The decrease in our intermediate generation volumes is primarily the result of the TransBay Cable becoming operational during the fourth quarter of 2010, which reduced the demand for our natural gas-fired Potrero generating unit. See note 19 for further information on the Potrero Settlement.

Other Operations. A decrease in our Other Operations intermediate generation as a result of transmission upgrades in 2009 which reduced the demand for the oil-fired intermediate units at our Canal generating facility and unplanned outages in 2010, partially offset by increases in generation volumes in our baseload and peaking units.

Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,336 MW at December 31, 2010 and four generating facilities with total net generating capacity of 5,204 MW at December 31, 2009.

The following table summarizes the results of operations of our Eastern PJM segment:

	2010	2009 (in millions)	Increase/ (Decrease)
Gross Margin:			
Energy	$ 384	$ 170	$ 214
Contracted and capacity	341	351	(10)
Realized value of hedges	280	586	(306)
Total realized gross margin	1,005	1,107	(102)
Unrealized gross margin	7	144	(137)
Total gross margin (excluding depreciation and amortization)	1,012	1,251	(239)
Operating Expenses:			
Operations and maintenance	495	434	61
Depreciation and amortization	142	98	44
Impairment losses	1,153	385	768
Gain on sales of assets, net	(3)	(14)	11
Total operating expenses, net	1,787	903	884
Operating income (loss)	$ (775)	$ 348	$ (1,123)

Gross Margin

The decrease of $102 million in realized gross margin was principally a result of the following:

a decrease of $306 million in realized value of hedges. In 2010 and 2009, realized value of hedges was $280 million and $586 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for coal exceeded market prices for coal; and

a decrease of $10 million in contracted and capacity primarily related to lower average capacity prices, offset in part by an increase in ancillary services revenue and additional megawatts of capacity sold in 2010; partially offset by

an increase of $214 million in energy, primarily as a result of an increase in the average settlement price for power, a decrease in the cost of emissions allowances, and higher generation volumes, offset in part by an increase in the average price of fuel.

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Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $7 million in 2010, which included a $326 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value was substantially offset by $319 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $144 million in 2009, which included a $633 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, partially offset by $489 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $884 million was primarily a result of the following:

- an increase of $768 million in impairment losses. In 2010, we recognized $1.2 billion in impairment losses, including $616 million related to the write-off of goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet and $537 million related to our Dickerson and Potomac River generating facilities. In 2009, we recognized $385 million in impairment losses, including $202 million related to our Potomac River generating facility and $183 million related to goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet. The goodwill impairment loss and related goodwill balance are eliminated upon consolidation at GenOn North America. See note 5(c) to our consolidated financial statements for additional information related to our impairment reviews;

- an increase of $44 million in depreciation and amortization expense primarily as a result of the scrubbers at our Maryland generating facilities that were placed in service in December 2009, offset in part by a decrease in the carrying value of the Potomac River generating facility as a result of the impairment charge taken in the fourth quarter of 2009;

- an increase of $32 million related to the recognition of a liability associated with our commitment to reduce particulate emissions at our Potomac River generating facility as part of the agreement with the City of Alexandria, Virginia because the planned capital investment would not be recovered in future periods based on the current projected cash flows for the Potomac River generating facility and the full impairment of the facility in 2010. See note 5(c) to our consolidated financial statements for additional information related to our impairment reviews;

- an increase of $29 million in operations and maintenance expense primarily as a result of an increase in costs related to the operation of the scrubbers at our Maryland generating facilities and the Montgomery County, Maryland CO_2 levy imposed on our Dickerson generating facility beginning in May 2010, offset in part by a decrease in planned maintenance costs in 2010 compared to 2009; and

- a decrease of $11 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Western PJM/MISO

Our Western PJM/MISO segment originated as a result of the Merger and includes 23 generating facilities (former RRI Energy generating facilities) with total net generating capacity of 7,483 MW at December 31, 2010.

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The following table summarizes the results of operations of our Western PJM/MISO segment from December 3, 2010 through December 31, 2010:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 33	$	$ 33
Contracted and capacity	32		32
Realized value of hedges			
Total realized gross margin	65		65
Unrealized gross margin	(22)		(22)
Total gross margin (excluding depreciation and amortization)	43		43
Operating Expenses:			
Operations and maintenance	45		45
Depreciation and amortization	9		9
Total operating expenses, net	54		54
Operating loss	$ (11)	$	$ (11)

California

Our California segment consists of eight generating facilities with total net generating capacity of 5,725 MW at December 31, 2010 and three generating facilities with total net generating capacity of 2,347 MW at December 31, 2009. Our California segment also includes business development efforts for new generation in California, including GenOn Marsh Landing.

The following table summarizes the results of operations of our California segment:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$	$	$
Contracted and capacity	126	122	4
Realized value of hedges			
Total realized gross margin	126	122	4
Unrealized gross margin			

Total gross margin (excluding depreciation and amortization)	126	122	4
Operating Expenses:			
Operations and maintenance	78	78	
Depreciation and amortization	31	22	9
Impairment losses		14	(14)
Gain on sales of assets, net			
Total operating expenses, net	109	114	(5)
Operating income	$ 17	$ 8	$ 9

Gross Margin

Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for 100% of the capacity from these units, and our Potrero units were subject to RMR arrangements in

2010 and 2009. In addition, we have some units in southern California that we operate under tolling agreements with other customers. Therefore, our gross margin generally is not affected by changes in power generation volumes from these facilities.

For those units that are not under tolling or RMR agreements, gross margin is affected by changes in power generation volumes as well as resource adequacy capacity sales.

Operating Expenses

The decrease of $5 million in operating expenses was principally a result of the following:

a decrease of $14 million of impairment losses related to our Potrero and Contra Costa generating facilities during 2009. See note 5(c) to our consolidated financial statements for additional information related to our impairments; partially offset by

an increase of $9 million in depreciation expense as a result of a decrease in the useful life of our Potrero generating facility because of the settlement with the City and County of San Francisco executed in the third quarter of 2009. See note 19 to our consolidated financial statements for additional information on the GenOn Potrero settlement with the City and County of San Francisco.

Energy Marketing

Our Energy Marketing segment consists of proprietary trading, fuel oil management and natural gas transportation and storage activities.

The following table summarizes the results of operations of our Energy Marketing segment:

	2010	**2009**	**Increase/ (Decrease)**
		(in millions)	
Gross Margin:			
Energy	$ 34	$ 167	$ (133)
Contracted and capacity			
Realized value of hedges			
Total realized gross margin	34	167	(133)
Unrealized gross margin	(8)	(113)	105
Total gross margin (excluding depreciation and amortization)	26	54	(28)
Operating Expenses:			
Operations and maintenance	9	11	(2)
Depreciation and amortization	1	1	
Total operating expenses, net	10	12	(2)
Operating income	$ 16	$ 42	$ (26)

Gross Margin

The decrease of $133 million in realized gross margin was principally a result of a $76 million decrease from proprietary trading activities and a $57 million decrease from our fuel oil management activities. The decrease in the contribution from proprietary trading was primarily a result of a decrease in the realized value associated with power positions in 2010 as compared to 2009. The decrease in the contribution from fuel oil management was a result of lower gross margin on positions used to hedge economically the fair value of our physical fuel oil inventory.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $8 million in 2010, which included $50 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, substantially offset by a $42 million net increase in the value of contracts for future periods; and

- unrealized losses of $113 million in 2009, which included $101 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $12 million net decrease in the value of contracts for future periods.

Other Operations

Our Other Operations segment consists of nine generating facilities with total net generating capacity of 5,055 MW at December 31, 2010 and four generating facilities with total net generating capacity of 2,535 MW at December 31, 2009. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified to another segment.

The following table summarizes the results of operations of our Other Operations segment:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 19	$ 23	$ (4)
Contracted and capacity	87	93	(6)
Realized value of hedges	13	43	(30)
Total realized gross margin	119	159	(40)
Unrealized gross margin	(19)	16	(35)
Total gross margin (excluding depreciation and amortization)	100	175	(75)
Operating Expenses:			
Operations and maintenance	219	86	133
Depreciation and amortization	41	28	13
Impairment losses	28	5	23
Gain on sales of assets, net	(1)	(4)	3
Total operating expenses, net	287	115	172
Operating income (loss)	$ (187)	$ 60	$ (247)

Gross Margin

The decrease of $40 million in realized gross margin was principally a result of the following:

a decrease of $30 million in realized value of hedges. In 2010 and 2009, realized value of hedges was $13 million and $43 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for fuel exceeded market prices for fuel;

a decrease of $6 million in contracted and capacity primarily related to decreases in capacity prices and megawatts of capacity sold; and

a decrease of $4 million in energy primarily as a result of a decrease in generation volumes from our oil-fired intermediate units at our Canal generating facility as a result of transmission upgrades in 2009, a decrease in the average settlement price for power and unplanned outages in 2010, offset in part by an increase in generation volumes at our Bowline generating facility.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $19 million in 2010 as a result of the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $16 million in 2009, which included a $65 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and fuel prices, partially offset by $49 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $172 million in operating expenses was principally the result of the following:

- an increase of $133 million in operations and maintenance expense primarily related to the following:

  - an increase of $114 million in merger-related costs incurred in 2010, which includes $67 million of advisory and legal costs and $35 million related to severance;

  - an increase of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, comprised of a $52 million reduction in operations and maintenance expense for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed, and a $10 million reversal of accruals for future funding to MC Asset Recovery. See note 18 to our consolidated financial statements for additional information related to the settlement between MC Asset Recovery and Southern Company; and

  - an increase of $24 million related to the accelerated vesting of Mirant s stock-based compensation as a result of the Merger; partially offset by

  - a decrease of $37 million primarily as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees. See note 8 to our consolidated financial statements for additional information related to the postretirement healthcare benefit curtailment;

  - a decrease of $20 million primarily related to lower property taxes because of a lower assessed value for the Lovett generating facility which was demolished in 2009 and a decrease in shutdown costs associated with this generating facility; and

  - a decrease of $12 million related to severance and stock-based compensation costs not related to the Merger primarily as a result of the departure of certain executives in 2009.

- an increase of $23 million in impairment losses. In 2010, we recognized $28 million in impairment losses for capitalized interest recorded at GenOn North America related to the Dickerson and Potomac River generating facilities. In 2009, we recognized $5 million in impairment losses for capitalized interest recorded at GenOn North America related to the Potomac River generating facility;

- an increase of $13 million in depreciation and amortization expense primarily as a result of the depreciation of interest capitalized at GenOn North America related to the scrubbers at our Maryland generating facilities that were placed in service in December 2009 and revisions to the useful lives of our assets as a result of a depreciation study completed in the first quarter of 2010; and

a decrease of $3 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Other Significant Consolidated Statements of Operations Comparison

Provision (Benefit) for Income Taxes

Provision (benefit) for income taxes changed by $14 million, primarily as a result of decreased federal taxable income reducing federal and state alternative minimum taxes.

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2009 Compared to 2008

Consolidated Financial Performance

We reported net income of $494 million and $1.3 billion for 2009 and 2008, respectively. The change in net income is detailed as follows:

	2009	2008	Increase/ (Decrease)
		(in millions)	
Realized gross margin	$ 1,552	$ 1,343	$ 209
Unrealized gross margin	47	786	(739)
Total gross margin (excluding depreciation and amortization)	1,599	2,129	(530)
Operating expenses:			
Operations and maintenance	609	667	(58)
Depreciation and amortization	149	144	5
Impairment losses	221		221
Gain on sales of assets, net	(22)	(39)	17
Total operating expenses, net	957	772	185
Operating income	642	1,357	(715)
Other expense, net:			
Interest expense, net	135	119	16
Equity in income of affiliates	1	16	(15)
Other, net		5	(5)
Total other expense, net	136	140	(4)
Income from continuing operations before income taxes	506	1,217	(711)
Provision for income taxes	12	2	10
Income from continuing operations	494	1,215	(721)
Income from discontinued operations		50	(50)
Net income	$ 494	$ 1,265	$ (771)

Realized Gross Margin. For 2009, our realized gross margin increase of $209 million was principally a result of the following:

an increase of $422 million in realized value of hedges. In 2009, realized value of hedges was $629 million, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for fuel exceeded market prices for fuel. In 2008, realized value of hedges was $207 million, which reflects the amount by which market prices for fuel exceeded contract prices for fuel, partially offset by the amount by which market prices for power exceeded the settlement value of power contracts; and

an increase of $13 million in contracted and capacity primarily related to higher capacity prices in 2009; partially offset by

a decrease of $226 million in energy, primarily as a result of a decrease in power prices, an increase in the cost of emissions allowances, including $45 million to comply with the RGGI in 2009, and lower generation volumes. The lower generation volumes were a result of lower demand and decreases in natural gas prices, which at times made it uneconomic for certain of our coal-fired units to generate. The decreases in energy gross margin were partially offset by a decrease in the price of fuel.

Unrealized Gross Margin. Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $47 million in 2009, which included a $686 million net increase in the value of hedge and trading contracts for future periods primarily related to decreases in forward power and natural gas prices, partially offset by $639 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $786 million in 2008, which included a $460 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and $326 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Operating Expenses. Our operating expenses increase of $185 million was primarily a result of the following:

- an increase of $221 million of impairment losses related to our Potomac River generating facility and intangible assets related to our Potrero and Contra Costa generating facilities during 2009. See note 5(c) to our consolidated financial statements for additional information related to our impairments; and

- a decrease of $17 million in gain on sales of assets, net in 2009; partially offset by

- a decrease of $58 million in operations and maintenance expense. The MC Asset Recovery settlement with Southern Company resulted in a $62 million reduction in operations and maintenance expense for 2009. See note 19 to our consolidated financial statements for additional information related to the settlement between MC Asset Recovery and Southern Company. Excluding the settlement, operations and maintenance expense increased $4 million.

Interest Expense, Net. Interest expense, net increased $16 million for 2009, and reflects lower interest income as a result of lower interest rates on invested cash and lower average cash balances in 2009 compared to 2008, partially offset by lower interest expense as a result of lower outstanding debt and higher interest capitalized on projects under construction.

Equity in Income of Affiliates. Equity in income of affiliates decreased $15 million primarily related to MC Asset Recovery. See note 15 to our consolidated financial statements.

Adjusted EBITDA and Adjusted Income from Continuing Operations. The following table reconciles the non-GAAP consolidated performance measures adjusted income from continuing operations and adjusted EBITDA to net income. See discussion above regarding changes in net income, including the significant items excluded or adjusted in arriving at the non-GAAP measures in the following table.

	2009	2008
	(in millions)	
Net Income	$ 494	$ 1,265
Income from discontinued operations		50
Income from continuing operations	494	1,215
Impairment losses	221	

Severance and bonus plan for dispositions	13	14
Lovett shut down costs	5	12
Lower of cost or market inventory adjustments, net	(31)	54
Unrealized gains	(47)	(786)
Bankruptcy charges and legal contingencies	(62)	
Loss on early extinguishment of debt		3
Other	1	5
Adjusted income from continuing operations	594	517
Depreciation and amortization	149	144
Interest expense, net	135	119
Provision for income tax	12	2
Adjusted EBITDA	$ 890	$ 782

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Segments

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business. We previously had four reportable segments: Mid-Atlantic, Northeast, California and Other Operations. In the fourth quarter of 2010, in conjunction with the Merger, we began reporting in five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. We reclassified amounts for 2009 and 2008 to conform to the current segment presentation.

In the tables below, for 2009 and 2008, the Eastern PJM segment consists of four generating facilities located in Maryland and Virginia. The California segment consists of three generating facilities located in California. The California segment also includes business development efforts for new generation in California, including GenOn Marsh Landing. The Energy Marketing segment consists of proprietary trading and fuel oil management activities. Other Operations consists of four generating facilities located in Massachusetts and New York. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified to another segment. In the following tables, eliminations are primarily related to intercompany sales of emissions allowances. The tables do not include the Western PJM/MISO segment as that segment was formed with assets acquired in the Merger.

Gross Margin Overview

The following tables detail realized and unrealized gross margin for 2009 and 2008, by operating segments:

	2009					
	Eastern PJM	California	Energy Marketing	Other Operations	Eliminations	Total
			(in millions)			
Energy	$ 170	$	$ 167	$ 23	$ (3)	$ 357
Contracted and capacity	351	122		93		566
Realized value of hedges	586			43		629
Total realized gross margin	1,107	122	167	159	(3)	1,552
Unrealized gross margin	144		(113)	16		47
Total gross margin(1)	$ 1,251	$ 122	$ 54	$ 175	$ (3)	$ 1,599

	2008					
	Eastern PJM	California	Energy Marketing	Other Operations	Eliminations	Total
			(in millions)			
Energy	$ 517	$ 4	$ (17)	$ 73	$ 6	$ 583
Contracted and capacity	340	123		90		553
Realized value of hedges	181			26		207

Total realized gross margin	1,038	127	(17)	189	6	1,343
Unrealized gross margin	676		120	(10)		786
Total gross margin[(1)]	$ 1,714	$ 127	$ 103	$ 179	$ 6	$ 2,129

(1) Gross margin excludes depreciation and amortization.

Energy represents gross margin from the generation of electricity, fuel sales and purchases at market prices, fuel handling, steam sales and our proprietary trading and fuel oil management activities.

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts (for 2009 and 2008), through tolling agreements and from ancillary services.

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Realized value of hedges represents the actual margin upon the settlement of our power and fuel hedging contracts and the difference between market prices and contract costs for fuel. Power hedging contracts include sales of both power and natural gas used to hedge power prices as well as hedges to capture the incremental value related to the geographic location of our physical assets.

Unrealized gross margin represents the net unrealized gain or loss on our derivative contracts, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

Operating Statistics

The following table summarizes net capacity factor by segment for 2009 and 2008:

	2009	2008	Increase/ (Decrease)
Eastern PJM	30%	33%	(3)%
California	5%	4%	1%
Energy Marketing	N/A	N/A	N/A
Other Operations	10%	13%	(3)%
Total	19%	21%	(2)%

The following table summarizes power generation volumes by segment for 2009 and 2008:

	2009	2008	Increase/ (Decrease)	Increase/ (Decrease)
	(in gigawatt hours)			
Eastern PJM:				
Baseload	13,500	14,350	(850)	(6)%
Intermediate	363	489	(126)	(26)%
Peaking	92	160	(68)	(43)%
Total Eastern PJM	13,955	14,999	(1,044)	(7)%
California:				
Intermediate	1,050	868	182	21%
Peaking	4	21	(17)	(81)%
Total California	1,054	889	165	19%
Other Operations:				
Baseload	1,425	1,131	294	26%
Intermediate	673	1,919	(1,246)	(65)%
Peaking	3	5	(2)	(40)%
Total Other Operations	2,101	3,055	(954)	(31)%

Total	17,110	18,943	(1,833)	(10)%

The total decrease in power generation volumes for 2009, as compared to 2008, is primarily the result of the following:

Eastern PJM. A decrease in our Eastern PJM baseload generation as a result of a decrease in demand in 2009 compared to 2008 and a decrease in natural gas prices, which at times made it uneconomic for certain of our coal-fired units to generate.

California. All of our California generating facilities operate under tolling agreements or are subject to RMR arrangements. Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for 100% of the capacity from these units and our Potrero units were subject to RMR arrangements in 2009 and 2008. Therefore, changes in power generation volumes from those generating facilities, which can be caused by weather, planned outages or other factors, generally did not affect our gross margin.

Other Operations. A decrease in our Other Operations intermediate generation as a result of transmission upgrades in 2009, which reduced the demand for certain of our intermediate units, partially offset by an increase in our Other Operations baseload generation as a result of an increase in market spark spreads.

Eastern PJM

Our Eastern PJM segment includes four generating facilities with total net generating capacity of 5,204 MW.

The following table summarizes the results of operations of our Eastern PJM segment:

	2009	2008	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 170	$ 517	$ (347)
Contracted and capacity	351	340	11
Realized value of hedges	586	181	405
Total realized gross margin	1,107	1,038	69
Unrealized gross margin	144	676	(532)
Total gross margin (excluding depreciation and amortization)	1,251	1,714	(463)
Operating Expenses:			
Operations and maintenance	434	412	22
Depreciation and amortization	98	92	6
Impairment losses	385		385
Gain on sales of assets, net	(14)	(8)	(6)
Total operating expenses, net	903	496	407
Operating income	$ 348	$ 1,218	$ (870)

Gross Margin

The increase of $69 million in realized gross margin was principally a result of the following:

an increase of $405 million in realized value of hedges. In 2009, realized value of hedges was $586 million, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for coal that we purchased under long-term agreements exceeded market prices for coal. In 2008, realized value of hedges was $181 million, which reflects the amount by which market prices for coal exceeded contract prices for coal that we purchased under long-term agreements, partially offset by the amount by which market prices for power exceeded the settlement value of power contracts; and an increase of $11 million in contracted and capacity primarily related to higher capacity prices in 2009; partially offset by

a decrease of $347 million in energy, primarily as a result of a decrease in power prices, an increase in the cost of emissions allowances, including $41 million to comply with the RGGI in 2009, and lower generation volumes. The lower generation volumes were a result of lower demand and decreases in natural gas prices, which at times made it uneconomic for certain of our coal-fired units to generate. These decreases were partially offset by a decrease in the price of coal.

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Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $144 million in 2009, which included a $633 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, partially offset by $489 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $676 million in 2008, which included a $399 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and $277 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $407 million in operating expenses was primarily a result of the following:

- an increase of $385 million in impairment losses recognized in the fourth quarter of 2009, including $202 million related to our Potomac River generating facility and $183 million related to goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet. The goodwill does not exist at GenOn s consolidated balance sheet. As such, the goodwill impairment loss and related goodwill balance are eliminated upon consolidation at GenOn North America. See note 5(c) to our consolidated financial statements for additional information related to our impairment of the Potomac River generating facility;

- an increase of $22 million in operations and maintenance expense primarily as a result of higher labor costs related to increased staffing levels in preparation for the operation of our scrubbers and an increase in Maryland property taxes, offset in part by a decrease in maintenance costs associated with a decrease in planned outages; and

- an increase of $6 million in depreciation and amortization expense primarily related to pollution control equipment for NO_x emissions that was placed in service in 2008 as part of our compliance with the Maryland Healthy Air Act; partially offset by

- an increase of $6 million in gain on sales of assets primarily related to emissions allowances sold to third parties.

California

Our California segment consists of three generating facilities with total net generating capacity of 2,347 MW and includes business development efforts for new generation in California, including Marsh Landing.

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The following table summarizes the results of operations of our California segment:

	2009	2008	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$	$ 4	$ (4)
Contracted and capacity	122	123	(1)
Realized value of hedges			
Total realized gross margin	122	127	(5)
Unrealized gross margin			
Total gross margin (excluding depreciation and amortization)	122	127	(5)
Operating Expenses:			
Operations and maintenance	78	76	2
Depreciation and amortization	22	23	(1)
Impairment losses	14		14
Gain on sales of assets, net		(7)	7
Total operating expenses, net	114	92	22
Operating income	$ 8	$ 35	$ (27)

Operating Expenses

The increase of $22 million in operating expenses was principally a result of the following:

an impairment loss of $14 million on intangible assets related to our Potrero and Contra Costa generating facilities during 2009. See note 5(c) to our consolidated financial statements for additional information related to our impairment reviews; and

a decrease of $7 million in gain on sales of assets primarily related to emissions allowances sold to third parties.

Energy Marketing

Our Energy Marketing segment consists of proprietary trading and fuel oil management activities.

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The following table summarizes the results of operations of our Energy Marketing segment:

	2009	2008	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 167	$ (17)	$ 184
Contracted and capacity			
Realized value of hedges			
Total realized gross margin	167	(17)	184
Unrealized gross margin	(113)	120	(233)
Total gross margin (excluding depreciation and amortization)	54	103	(49)
Operating Expenses:			
Operations and maintenance	11	10	1
Depreciation and amortization	1	1	
Total operating expenses, net	12	11	1
Operating income	$ 42	$ 92	$ (50)

Gross Margin

The increase of $184 million in realized gross margin was principally a result of the following:

- an increase of $184 million in energy primarily as a result of $112 million increase from our fuel oil management activities and a $72 million increase from proprietary trading activities. The increase from our fuel oil management activities includes a $25 million gain from the sale of excess fuel oil in 2009 and a $37 million lower of cost or market fuel oil inventory adjustment recognized in the fourth quarter of 2008. The increase in gross margin from proprietary trading activities was a result of higher realized value associated with power positions in 2009 as compared to 2008.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $113 million in 2009, which included $101 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $12 million net decrease in the value of contracts for future periods; and

- unrealized gains of $120 million in 2008, which included a $65 million net increase in the value of contracts for future periods and $55 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period.

Other Operations

Other Operations consists of four generating facilities located in Massachusetts and New York with total net generating capacity of 2,535 MW. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified to another segment.

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The following table summarizes the results of operations of our Other Operations segment:

	2009	2008	Increase/ (Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 23	$ 73	$ (50)
Contracted and capacity	93	90	3
Realized value of hedges	43	26	17
Total realized gross margin	159	189	(30)
Unrealized gross margin	16	(10)	26
Total gross margin (excluding depreciation and amortization)	175	179	(4)
Operating Expenses:			
Operations and maintenance	86	169	(83)
Depreciation and amortization	28	28	
Impairment losses	5		5
Gain on sales of assets, net	(4)	(32)	28
Total operating expenses, net	115	165	(50)
Operating income	$ 60	$ 14	$ 46

Gross Margin

The decrease of $30 million in realized gross margin was principally a result of the following:

a decrease of $50 million in energy, primarily as a result of a 31% decrease in generation volumes because of transmission upgrades which reduced the need for the Canal generating facility to operate, a decrease in power prices, an increase in the cost of emissions allowances, including $4 million to comply with the RGGI in 2009 and the shutdown of the Lovett generating facility in 2008 offset in part by lower fuel costs; partially offset by

an increase of $17 million in realized value of hedges. In 2009, realized value of hedges was $43 million, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for fuel exceeded market prices for fuel. In 2008, realized value of hedges was $26 million, which reflects the amount by which market prices for fuel exceeded contract prices for fuel and the amount by which the settlement value of power contracts exceeded market prices for power.

Our unrealized gross margin for both periods reflects the following:

unrealized gains of $16 million in 2009, which included a $65 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and fuel prices, partially offset by $49 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

unrealized losses of $10 million in 2008, which included $6 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $4 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power and fuel prices.

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Operating Expenses

The decrease of $50 million in operating expenses was principally the result of the following:

a decrease of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, including a $52 million reduction in operations and maintenance expense for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed and a $10 million reversal of accruals for future funding to MC Asset Recovery. See note 19 to our consolidated financial statements for additional information related to the settlement between MC Asset Recovery and Southern Company;

a decrease of $41 million in operations and maintenance expense primarily related to the shutdown of the Lovett generating facility in April 2008 and lower maintenance expense as a result of planned outages at the Canal generating facility in 2008; and

a decrease of $10 million related to the bonus plan for dispositions that ended in June 2008; partially offset by

a decrease of $28 million in gain on sales of assets primarily related to emissions allowances sold to third parties;

an increase of $15 million related to other operations and maintenance expenses;

an increase of $9 million related to severance and stock-based compensation costs primarily as a result of the departure of certain executives in 2009;

an increase of $5 million in impairment losses recognized in the fourth quarter of 2009 for capitalized interest recorded at GenOn North America related to the Potomac River generating facility; and

an increase related to a curtailment gain on pension and postretirement benefits of $5 million related to the shutdown of the Lovett generating facility in April 2008.

Other Significant Consolidated Statements of Operations Comparison

Provision for Income Taxes

Provision for income taxes increased $10 million, which includes an increase in our federal alternative minimum tax of $7 million and an increase in our state income taxes of $3 million primarily as a result of a change in 2008 in the State of California s tax law that suspended the utilization of net operating loss carry forwards for the 2008 and 2009 tax years.

Discontinued Operations

For 2008, income from discontinued operations was $50 million and included insurance recoveries related to the Sual generating facility outages that occurred prior to the 2007 sale of the Philippine business and final working capital adjustments related to the 2007 sale of the Caribbean business.

Financial Condition

Liquidity and Capital Resources

Management thinks that our liquidity position and cash flows from operations will be adequate to fund operating, maintenance and capital expenditures, to fund debt service and to meet other liquidity requirements. Management regularly monitors our ability to fund our operating, financing and investing activities. See note 6 to our consolidated financial statements for additional discussion of our debt.

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Debt Financing Transactions Related to the Merger

Debt Issuances:

Senior Secured Term Loan Facility and Revolving Credit Facility

On September 20, 2010, we entered into a credit agreement, which provides for:

- a $700 million seven-year senior secured term loan facility with a rate of LIBOR + 4.25% (with a LIBOR floor of 1.75%); and
- a $788 million five-year senior secured revolving credit facility, with an undrawn rate of 0.75% and a drawn rate of LIBOR + 3.50%.

We refer to the new term loan facility and the new revolving facility collectively as the GenOn credit facilities. The term loan facility was funded at the close of the Merger on December 3, 2010. Although $275 million of outstanding letters of credit were transferred from pre-merger credit facilities, we did not make any borrowings under the revolving credit facility at closing.

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At December 31, 2010, outstanding letters of credit were $267 million and availability of borrowings under the revolving credit facility was $521 million.

The GenOn credit facilities, and the subsidiary guarantees thereof, are senior secured obligations of GenOn and certain of its existing and future direct and indirect subsidiaries, excluding GenOn Americas Generation; provided, however, that certain of GenOn Americas Generation s subsidiaries (other than GenOn Mid-Atlantic and GenOn Energy Management and their subsidiaries) guarantee the GenOn credit facilities to the extent permitted under the indenture for the senior notes of GenOn Americas Generation. GenOn Americas became a co-borrower under the GenOn credit facilities upon the closing of the Merger.

Senior Unsecured Notes, Due 2018 and 2020

On October 4, 2010, GenOn Escrow issued two series of senior unsecured notes:

- $675 million of 9.5% senior notes due 2018; and
- $550 million of 9.875% senior notes due 2020.

Upon issuance, the proceeds of the notes (which were issued at a discount), together with additional funds, were deposited into a segregated escrow account pending completion of the Merger. Upon completion of the Merger, GenOn Escrow merged with and into GenOn which assumed all of GenOn Escrow s obligations under the notes and the related indenture and the funds held in escrow were released to GenOn.

Discharge, Defeasance, Redemption and Repayment of Debt:

The proceeds from the merger-related debt issuances described above were used to fund:

- the discharge and, on January 3, 2011, redemption of the $285 million (principal and 2.25% premium) GenOn senior secured notes due 2014 (issued in 2004) and $866 million (principal and 1.844% premium) GenOn

North America senior unsecured notes due 2013 (issued in 2005);

the defeasance and, in June 2011, redemption of the $382 million (principal and 3% premium) PEDFA 6.75% bonds due 2036 (issued in 2004);

the payment of the $305 million GenOn North America senior secured term loan maturing in 2013 (entered into in 2006); and

the payment of certain related fees and expenses, including accrued interest.

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Sources of Funds and Capital Structure

Maintaining sufficient liquidity in our business is crucial in order to mitigate the risk of future financial distress to us. Accordingly, we plan on a prospective basis for the expected liquidity requirements of our business considering the factors listed below:

- expected expenditures with respect to maintenance activities and capital improvements, and related outages;
- expected collateral postings in support of our business;
- effects of market price volatility on the amount of collateral postings for hedge transactions and risk management transactions;
- effects of market price volatility on fuel pre-payment requirements;
- seasonal and intra-month working capital requirements;
- the development and construction of new generating facilities, including GenOn Marsh Landing;
- debt service obligations; and
- costs associated with litigation, regulatory and tax proceedings.

The principal sources of our liquidity are expected to be: (a) existing cash on hand and expected cash flows from the operations of our subsidiaries, (b) letters of credit issued or borrowings made under the GenOn senior secured revolving credit facility and (c) letters of credit issued or borrowings made under the GenOn Marsh Landing project financing.

Our operating cash flows may be affected by, among other things: (a) demand for electricity; (b) the difference between the cost of fuel used to generate electricity and the market value of the electricity generated; (c) commodity prices (including prices for electricity, emissions allowances, natural gas, coal and oil); (d) operations and maintenance expenses in the ordinary course; (e) planned and unplanned outages; (f) terms with trade creditors; and (g) cash requirements for capital expenditures relating to certain facilities (including those necessary to comply with environmental regulations).

The table below sets forth total cash, cash equivalents and availability under credit facilities of GenOn and its subsidiaries at December 31, 2010 (in millions):

Cash and Cash Equivalents:	
GenOn (excluding GenOn Mid-Atlantic and REMA)	$ 2,179
GenOn Mid-Atlantic	202
REMA	21
Total cash and cash equivalents	2,402
Less: cash reserved for other purposes	(11)
Total available cash and cash equivalents	2,391

Availability under GenOn credit facilities[(1)]	521
Total available cash, cash equivalents and availability under GenOn credit facilities[(1)]	$ 2,912

(1) Availability under the GenOn credit facilities does not include availability under the project financing described below under GenOn Marsh Landing Credit Facility.

We consider all short-term investments with an original maturity of three months or less to be cash equivalents. At December 31, 2010, except for amounts held in bank accounts to cover upcoming payables, all of our cash and cash equivalents were invested in AAA-rated United States Treasury money market funds.

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We and certain of our subsidiaries, including GenOn Americas Generation, are holding companies. The chart below is a summary representation of our capital structure and is not a complete corporate organizational chart.

(1) The GenOn credit facilities are guaranteed by certain direct and indirect subsidiaries of GenOn excluding GenOn Americas Generation; provided, however, that certain of GenOn Americas Generation s subsidiaries (other than GenOn Mid-Atlantic and GenOn Energy Management and their subsidiaries) guarantee the GenOn credit facilities to the extent permitted under the indenture for the senior notes of GenOn Americas Generation. GenOn Americas is a co-borrower under the GenOn credit facilities and the term loan balance is recorded at GenOn Americas.

(2) At December 31, 2010, the present values of lease payments under the GenOn Mid-Atlantic and REMA operating leases were approximately $927 million and $488 million, respectively (assuming a 10% and 9.4% discount rate, respectively) and the termination values of the GenOn Mid-Atlantic and REMA operating leases were $1.4 billion and $752 million, respectively.

(3) At December 31, 2010, GenOn Marsh Landing had not drawn on its credit facility. See GenOn Marsh Landing Credit Facility below for discussion.

Except for existing cash on hand, GenOn and GenOn Americas Generation are holding companies that are dependent on the distributions and dividends of their subsidiaries for liquidity. A substantial portion of cash from our operations is generated by GenOn Mid-Atlantic.

The ability of certain of our subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At December 31, 2010, GenOn Mid-Atlantic and REMA satisfied the respective restricted payments tests.

Pursuant to the terms of their respective lease and debt documents, GenOn Mid-Atlantic, REMA and GenOn Marsh Landing are restricted from, among other actions, (a) encumbering assets, (b) entering into business combinations or divesting assets, (c) incurring additional debt, (d) entering into transactions with affiliates on other than an arm s length basis or (e) materially changing their business. Therefore, at December 31, 2010, all of GenOn Mid-Atlantic s net assets (excluding cash) and all of REMA s net assets (excluding cash) were deemed restricted for purposes of Rule 4-08(e)(3)(ii) of Regulation S-X. The amounts of the deemed restricted net assets were as follows:

	December 31,	
	2010	2009
	(in millions)	
GenOn Mid-Atlantic	$ 3,698	$ 4,761
REMA	303	
GenOn Marsh Landing	80	6
Total restricted net assets	$ 4,081	$ 4,767

The ability of GenOn Americas Generation to pay its obligations is dependent on the receipt of dividends from GenOn North America, capital contributions or intercompany loans from GenOn and its ability to refinance all or a portion of those obligations as they become due. Although we continue to evaluate our refinancing options, we expect to maintain adequate liquidity to retire the $535 million of GenOn Americas Generation senior notes that come due in May 2011.

GenOn Marsh Landing Credit Facility

On October 8, 2010, GenOn Marsh Landing entered into a credit agreement for up to approximately $650 million of commitments to provide construction and permanent financing for the Marsh Landing generating facility. The credit facility consists of a $155 million tranche A senior secured term loan facility, a $345 million tranche B senior secured term loan facility, a $50 million senior secured letter of credit facility to support GenOn Marsh Landing s debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing s collateral requirements under its PPA with PG&E. The term loans are expected to be drawn during the construction of the project upon the satisfaction of the conditions precedent thereto, including the receipt by GenOn Marsh Landing of base equity contributions of $147 million. Prior to the commercial operation date of the project, the collateral requirements under the PPA and construction contracts are being met by a $165 million cash collateralized letter of credit facility entered into by GenOn Energy Holdings on behalf of GenOn Marsh Landing on September 27, 2010. At or near the commercial operation date of the project those collateral requirements will terminate. At December 31, 2010, GenOn Marsh Landing had not drawn on its credit facility.

The term loans are to be fully amortized by their maturity dates. The tranche A term loan matures on December 31, 2017 and the tranche B term loan matures on the date that is the earlier of the last day of the first fiscal quarter following the tenth anniversary of the conversion of the credit facility from a construction facility to a permanent facility upon commercial operation of the Marsh Landing project and December 31, 2023. The expiry date of the letters of credit is December 31, 2017. Interest on the tranche A term loans will be based on a base rate or a LIBOR rate plus an initial applicable margin of 1.5% for base rate loans and 2.5% for LIBOR loans (with such margin increasing 0.25% every three years). Interest on the tranche B term loans will be based on a base rate or a LIBOR rate plus an initial applicable margin of 1.75% for base rate loans and 2.75% for LIBOR loans (with such margin increasing 0.25% every three years). Fees on lenders exposure under the letters of credit accrue at a rate equal to the applicable margin payable on the tranche A term loans that are based on the LIBOR rate. An undrawn commitment fee applies at a rate of 0.75% per annum.

In connection with the credit agreement, GenOn Marsh Landing entered into interest rate swaps to mitigate the interest rate risks with respect to the term loan. GenOn Energy Holdings provided limited guarantees in respect of the interest rate swaps. The effective interest rate that GenOn Marsh Landing will pay for the term loan from the commercial operations date is 5.91% (plus the step-up in margin over time). The interest rate swaps will be accounted for as cash flow hedges with changes in fair value recognized in other comprehensive income, with the exception of any ineffectiveness which will be recognized in the consolidated statement of operations. GenOn expects the interest rate swaps to remain highly effective in mitigating the interest rate risk.

Uses of Funds

Our requirements for liquidity and capital resources, other than for the day-to-day operation of our generating facilities, are significantly influenced by the following items: (a) capital expenditures, (b) debt service, (c) payments under the GenOn Mid-Atlantic and REMA operating leases, (d) collateral required for our asset management and proprietary trading and fuel oil management activities and (e) the development and construction of new generating facilities, in particular the GenOn Marsh Landing generating facility.

Capital Expenditures. Our capital expenditures, excluding capitalized interest, during 2010, were $298 million. Our estimated capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for 2011 and 2012 are $592 million and $432 million, respectively. See Item 1, Business for further discussion of our capital expenditures.

Debt Service. At December 31, 2010, we had $6.1 billion of long-term debt ($2.1 billion of which was classified as current) with expected interest payments of $370 million for 2011. See note 6 to our consolidated financial statements.

GenOn Mid-Atlantic Operating Leases. GenOn Mid-Atlantic leases a 100% interest in both the Dickerson and Morgantown baseload units and associated property through 2029 and 2034, respectively. GenOn Mid-Atlantic has an option to extend the leases. Any extensions of the respective leases would be for less than 75% of the economic useful life of the facility, as measured from the beginning of the original lease term through the end of the proposed remaining lease term. We are accounting for these leases as operating leases. Although there is variability in the scheduled payment amounts over the lease term, we recognize rent expense for these leases on a straight-line basis in accordance with GAAP. Rent expense under the GenOn Mid-Atlantic leases was $96 million for each of 2010, 2009 and 2008. The scheduled payment amounts for the GenOn Mid-Atlantic leases are $134 million and $132 million for

2011 and 2012, respectively. At December 31, 2010, the total notional minimum lease payments for the remaining term of the leases aggregated $1.7 billion and the aggregate termination value for the leases was approximately $1.4 billion and generally decreases over time. In addition, the present value of lease payments at December 31, 2010 was approximately $927 million (assuming a 10% discount rate). GenOn provides letters of credit in support of GenOn Mid-Atlantic s lease obligations to post rent reserves in an aggregate amount equal to the greatest of the next six months scheduled rent payments, 50% of the next 12 months scheduled rent payments or $75 million.

REMA Operating Leases. REMA leases 16.45% and 16.67% interests in the Conemaugh and Keystone baseload facilities, respectively through 2034 and we expect to make payments through 2029. REMA also leases a 100% interest in the Shawville baseload facility through 2026 and we expect to make payments through that date. At the expiration of these leases, there are several renewal options related to fair value. We are accounting for these leases as operating leases and recognize rent expense on a straight-line basis of $34 million per year. Rent expense totaled $3 million during December 2010. The scheduled payment amounts for the REMA leases are $63 million and $56 million for 2011 and 2012, respectively. At December 31, 2010, the total notional minimum lease payments for the remaining term of the leases aggregated $882 million and the aggregate termination value for the leases was approximately $752 million and generally decreases over time. In addition, the present value of lease payments at December 31, 2010 was approximately $488 million (assuming a 9.4% discount rate). GenOn provides letters of credit in support of REMA s lease obligations to post rent reserves in an aggregate amount equal to the greater of the next six months scheduled rent payment or 50% of the next 12 months scheduled rent payments. See note 6 to our consolidated financial statements for further discussion on letters of credit.

Cash Collateral and Letters of Credit. In order to sell power and purchase fuel in the forward markets and perform other energy trading and marketing activities, we often are required to provide credit support to our counterparties or make deposits with brokers. In addition, we often are required to provide cash collateral or letters of credit as credit support for various contractual and other obligations incurred in connection with our commercial and operating activities, including obligations in respect of transmission and interconnection access, participation in power pools, rent reserves, power purchases and sales, fuel and emission purchases and sales, construction and equipment purchases and other operating activities. Credit support includes cash collateral, letters of credit, surety bonds and financial guarantees. In the event that we default, the counterparty can draw on a letter of credit or apply cash collateral held to satisfy the existing amounts outstanding under an open contract. At December 31, 2010, we had $265 million of posted cash collateral and $267 million of letters of credit outstanding under our revolving credit facility primarily to support our asset management activities, trading activities, rent reserve requirements and other commercial arrangements. In addition, we issued $106 million of cash-collateralized letters of credit in support of the Marsh Landing project. Our liquidity requirements are highly dependent on the level of our hedging activities, forward prices for energy, emissions allowances and fuel, commodity market volatility, credit terms with third parties and regulation of energy contracts. See Item 1, Business for our discussion on the Dodd-Frank Act. See note 6 to our consolidated financial statements.

The following table summarizes cash collateral posted with counterparties and brokers, letters of credit issued and surety bonds provided:

	December 31, 2010	December 31, 2009
	(in millions)	
Cash collateral posted energy trading and marketing	$ 220	$ 41
Cash collateral posted other operating activities	45	43
Letters of credit rent reserves	133	101
Letters of credit Marsh Landing project	106	12
Letters of credit energy trading and marketing	96	51
Letters of credit other operating activities	38	47
Surety bonds[1]	50	5

Total	$ 688	$ 300

(1) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations.

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

Our debt obligations, off-balance sheet arrangements and contractual obligations at December 31, 2010, are as follows:

	Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations by Year				
	Total	Less Than One Year	One to Three Years	Three to Five Years	More than Five Years
	(in millions)				
Long-term debt	$ 9,309	$ 2,416	$ 723	$ 1,279	$ 4,891
GenOn Mid-Atlantic operating leases	1,730	134	270	241	1,085
REMA operating leases	882	63	120	120	579
Other operating leases	227	72	59	37	59
Fuel commitments	1,343	789	554		
Commodity transportation commitments	652	72	143	131	306
LTSA commitments	441	12	18	37	374
Maryland Healthy Air Act	155	155			
GenOn Marsh Landing	475	216	258	1	
Other	592	365	93	75	59
Total payments	$ 15,806	$ 4,294	$ 2,238	$ 1,921	$ 7,353

Our contractual obligations table does not include our derivative obligations reported at fair value (other than fuel supply commitments), which are discussed in note 4 to our consolidated financial statements and asset retirement obligations, which are discussed in note 5 to our consolidated financial statements.

Long-term debt includes the current portion of long-term debt and long-term debt on our consolidated balance sheets, which are discussed in note 6 to our consolidated financial statements. Long-term debt also includes estimated interest on debt. Interest on our variable interest debt is based on the LIBOR curve at December 31, 2010. These amounts do not include any fair value adjustments or unamortized debt discounts or premiums.

GenOn Mid-Atlantic operating leases relate to our minimum lease payments associated with our off-balance sheet leases of the Dickerson and Morgantown baseload units. REMA operating leases relate to our minimum lease payments associated with our off-balance sheet leases of a 16.45% interest in the Conemaugh facility, a 16.67% interest in the Keystone facility and a 100% interest in the Shawville facility. In addition, we have commitments under other operating leases with various terms and expiration dates.

Fuel and commodity transportation commitments primarily relate to coal agreements and commodity transportation agreements.

Long-term service agreements relate to contracts that cover some periodic maintenance, including parts, on power generation turbines. The long-term service agreements terminate from 2014 to 2038 based on turbine usage.

Maryland Healthy Air Act commitments reflect the remaining expected payments for capital expenditures to comply with the limitations for SO_2, NO_x and mercury emissions under the Maryland Healthy Air Act. We completed the installation of the remaining pollution control equipment related to compliance with the Maryland Healthy Air Act in the fourth quarter of 2009. However, provisions in our construction contracts provide that certain payments be made after final completion of the project.

GenOn Marsh Landing development project reflects the current projected commitments related to our construction of the Marsh Landing generating facility.

Other primarily represents the open purchase orders less invoices received related to general procurement of products and services purchased in the ordinary course of business. These include construction, maintenance and labor activities at our generating facilities. Other also includes our estimated pension and other postretirement benefit funding obligations, deferred compensation plans, liabilities related to the accounting for uncertainty in income taxes and miscellaneous noncurrent liabilities.

Historical Cash Flows

2010 Compared to 2009

Operating Activities. The changes in our operating cash flows are detailed as follows:

	2010	2009	Increase/ (Decrease)
		(in millions)	
Operating income (loss)	$ (324)	$ 642	$ (966)
Non-cash items[1]	918	364	554
Receivables and accounts payable and accrued liabilities, net	(17)	8	(25)
Funds on deposit	(42)	21	(63)
Inventories	(65)	(35)	(30)
Interest payments, net of amounts capitalized	(244)	(124)	(120)
Income tax payments, net of refunds	1	(9)	10
Prepaid rent	(44)	(46)	2
Other, net	16	(8)	24
Net cash provided by operating activities of continuing operations	199	813	(614)
Net cash provided by operating activities of discontinued operations	6	9	(3)
Net cash provided by operating activities	$ 205	$ 822	$ (617)

(1) See our consolidated statements of cash flows for additional information.

Continuing Operations

Our cash provided by operating activities is affected by seasonality, changes in energy prices and fluctuations in our working capital requirements. Net cash provided by operating activities from continuing operations decreased by $614 million during 2010, compared to 2009, primarily as a result of the following:

Realized gross margin. A decrease in cash provided of $213 million in 2010, compared to 2009, excluding a decrease in non-cash lower of cost or market fuel inventory adjustments of $10 million. See Results of Operations in this Item 7 for additional discussion of our performance in 2010 compared to 2009;

Operating expenses. An increase in cash used for operations and maintenance expense of $228 million primarily related to the Merger costs, the operation of the scrubbers at our Maryland generating facilities in 2010 and the 2009 MC Asset Recovery settlement. In 2009, we were reimbursed $52 million of cash as a result of the MC Asset Recovery settlement with Southern Company for funds that we provided to MC Asset Recovery and costs that we incurred related to MC Asset Recovery that had not been previously reimbursed. See Results of Operations in this Item 7 for additional discussion of our performance in 2010 compared to

2009;

Interest payments, net of amounts capitalized. An increase in cash used of $120 million primarily as a result of a decrease in capitalized interest (which is included in investing activities) and additional interest payments associated with the debt assumed in connection with the Merger;

Funds on deposit. An increase in cash used of $63 million primarily as a result of postings of $42 million during 2010 compared to $21 million returned by our counterparties during 2009;

Inventories. An increase in cash used of $30 million primarily as a result of higher prices and purchases of a larger volume of fuel oil; and

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Receivables and accounts payable and accrued liabilities, net. An increase in cash used of $25 million primarily related to a $49 million increase in receivables outstanding subsequent to the Merger, partially offset by a $21 million decrease in cash collateral returned to our counterparties during 2010 compared to 2009 and a $9 million decrease in cash used for settlement of bankruptcy related claims and expenses.

The increases in cash used in and decreases in cash provided by operating activities were partially offset by the following:

Changes in other working capital, net. A decrease in cash used of $47 million primarily related to a decrease in property tax payments, income tax payments and prepaid property and general liability insurance during 2010 compared to 2009.

Discontinued Operations

During 2010 and 2009, net cash provided by operating activities from discontinued operations was primarily from the sale of transmission credits from our previously owned Wrightsville generating facility.

Investing Activities. The changes in our investing cash flows are detailed as follows:

	2010	2009 (in millions)	Increase/ (Decrease)
Cash acquired from RRI Energy, Inc.	$ 717	$	$ 717
Capital expenditures	(304)	(676)	372 (1)
Proceeds from the sales of assets	4	26	(22)(2)
Capital contributions		(5)	5 (3)
Restricted deposits payments	(1,586)		(1,586)(4)
Restricted deposits withdrawals	41	1	40 (5)
Other, net	(43)	3	(46)(6)
Net cash used in investing activities	$ (1,171)	$ (651)	$ (520)

(1) Primarily related to placing scrubbers for our Maryland generating facilities in service during the fourth quarter of 2009 as part of our compliance with the Maryland Healthy Air Act.

(2) Primarily related to sales of emissions allowances in 2009 as compared to 2010.

(3) Related to our obligation to fund MC Asset Recovery in 2009 which, in 2010, we were no longer obligated to fund.

(4) Includes $1.545 billion related to the discharge of the GenOn senior secured notes and GenOn North America senior notes and the defeasance of the PEDFA fixed-rate bonds (see note 6 to our consolidated financial statements for further discussion).

(5) Primarily related to withdrawals from the escrow account for the payment of accrued interest on debt to be discharged.

(6) Primarily related to the funding of Rabbi Trusts established during 2010 to fund severance payments and non-qualified deferred compensation plans for certain key employees in connection with the Merger.

Financing Activities. The changes in our financing cash flows are detailed as follows:

	2010	2009 (in millions)	Increase/ (Decrease)
Proceeds from issuance of long-term debt	$ 1,896(1)	$	$ 1,896
Repayments of long-term debt	(379)(2)	(45)(2)	(334)
Debt issuance costs	(92)(3)		(92)
Share repurchases	(11)	(4)	(7)
Proceeds from exercises of stock options and warrants	1		1
Net cash provided by (used in) financing activities	$ 1,415	$ (49)	$ 1,464

(1) Includes issuance of $700 million senior secured term loan (issued at a discount for $693 million) and $1.225 billion senior unsecured notes (issued at a discount for $1.203 billion).

(2) Includes $373 million related to the repayment of the GenOn North America senior secured term loan.

(3) Represents $68 million of costs paid for issuance of debt in connection with the Merger and $24 million of costs paid in connection with entering into the GenOn Marsh Landing credit facility.

2009 Compared to 2008

Operating Activities. The changes in our operating cash flows are detailed as follows:

	2009	2008 (in millions)	Increase/ (Decrease)
Operating income	$ 642	$ 1,357	$ (715)
Non-cash items[1]	364	(588)	952
Receivables and accounts payable and accrued liabilities, net	8	(11)	19
Funds on deposit	21	104	(83)
Inventories	(35)	47	(82)
Pension plans contributions		(64)	64
Interest payments, net of amounts capitalized	(124)	(175)	51
Income tax payments, net of refunds	(9)		(9)
Interest income	3	70	(67)
Prepaid rent	(46)	(24)	(22)
Other, net	(11)	(19)	8
Net cash provided by operating activities of continuing operations	813	697	116
Net cash provided by operating activities of discontinued operations	9	50	(41)

Net cash provided by operating activities	$ 822	$ 747	$ 75

(1) See our consolidated statements of cash flows for additional information.

Continuing Operations

Our cash provided by operating activities is affected by seasonality, changes in energy prices and fluctuations in our working capital requirements. Net cash provided by operating activities from continuing operations increased $116 million during 2009, compared to 2008, primarily as a result of the following:

Realized gross margin. An increase in cash provided of $176 million in 2009, compared to 2008, excluding a decrease in non-cash lower of cost or market fuel inventory adjustments of $33 million. See Results of Operations for additional discussion of our performance in 2009 compared to 2008;

Operations and maintenance expense. A decrease in cash used for operations and maintenance expense of $70 million during 2009, which includes a $52 million cash reimbursement as a result of the MC Asset Recovery settlement with Southern Company. See Results of Operations for additional discussion of our performance in 2009 compared to 2008;

Receivables and accounts payable and accrued liabilities, net. An increase in cash provided of $19 million during 2009 primarily related to (a) a decrease in power prices in 2009 compared to the same period in 2008 and (b) the implementation in June 2009 of weekly settlements with PJM (in lieu of monthly settlements) which reduced the amount of outstanding receivables for the PJM markets, partially offset by an increase in cash used of $111 million as a result of $43 million collateral returned to counterparties during 2009 as compared to $68 million received from counterparties during 2008;

Interest payments, net of amounts capitalized. A decrease in cash used of $51 million primarily as a result of lower outstanding debt and higher interest capitalized on projects under construction; and

Pension plan contributions. A decrease in cash used of $64 million as there were no pension plan contributions during 2009 compared to $64 million in contributions during 2008.

The decreases in cash used in and increases in cash provided by operating activities were partially offset by the following:

Funds on deposit. A decrease in cash provided of $83 million. During 2009, we received net cash of $21 million related to $33 million of net cash collateral returned to us partially offset by $12 million related to funds posted in connection with the Marsh Landing PPA with PG&E. During 2008, we had net cash collateral returned to us of $104 million primarily related to the cash collateral account to support issuance of letters of credit under the GenOn North America senior secured term loan;

Inventories. An increase of cash used of $82 million as a result of higher inventory levels of coal and fuel oil, partially offset by lower market prices in 2009 as compared to 2008;

Prepaid rent. An increase in cash used for our GenOn Mid-Atlantic operating leases as the scheduled rent payments were higher by $22 million during 2009 than during 2008; and

Interest income. A decrease in cash provided of $67 million primarily as a result of lower interest rates on invested cash, as well as lower average cash balances.

Discontinued Operations

In 2009, net cash provided by operating activities from discontinued operations was from the sale of transmission credits from our previously owned Wrightsville generating facility. During 2008, net cash provided by operating activities from discontinued operations was primarily a result of $41 million of business interruption insurance recoveries related to the outages of the Sual generating facility and the sale of transmission credits for $7 million from our previously owned Wrightsville generating facility.

Investing Activities. The changes in our investing cash flows are detailed as follows:

Increase/

	2009	2008	(Decrease)
		(In millions)	
Capital expenditures	$ (676)	$ (731)	$ 55(1)
Proceeds from the sales of assets	26(2)	42(2)	(16)
Capital contributions	(5)	(20)	15
Restricted deposits payments		(34)	34(3)
Other, net	4	4	
Net cash used in investing activities of continuing operations	(651)	(739)	88
Net cash provided by investing activities of discontinued operations		25(4)	(25)
Net cash used in investing activities	$ (651)	$ (714)	$ 63

(1) Primarily related to our environmental capital expenditures for our Maryland generating facilities related to our compliance with the Maryland Healthy Air Act.

(2) Primarily related to sales of emissions allowances to third parties.

(3) Related to $34 million placed in an escrow account in September 2008, to satisfy the conditions of Potomac River s agreement with the City of Alexandria, Virginia. See note 19 to our consolidated financial statements for additional information on Potomac River s agreement with the City of Alexandria, Virginia.

(4) Primarily related to insurance recoveries for repairs to the Sual generating facility and the Swinging Bridge generating facility.

Financing Activities. The changes in our financing cash flows are detailed as follows:

	2009	2008 (in millions)	Increase/ (Decrease)
Share repurchases	$ (4)	$ (2,761)	$ 2,757
Repayments and purchases of long-term debt	(45)	(420)[1]	375
Proceeds from exercises of stock options and warrants		18	(18)
Net cash used in financing activities	$ (49)	$ (3,163)	$ 3,114

(1) Includes $276 million for the 2008 purchase and retirement of GenOn Americas Generation senior notes due in 2011.

Critical Accounting Estimates

The accounting policies described below are considered critical to obtaining an understanding of our consolidated financial statements because their application requires significant estimates and judgments by management in preparing our consolidated financial statements. Management s estimates and judgments are inherently uncertain and may differ significantly from actual results achieved. Management considers an accounting estimate to be critical if the following conditions apply:

- the estimate requires significant assumptions; and
- changes in the estimate could have a material effect on our consolidated results of operations or financial condition; or
- if different estimates that could have been selected had been used, there could be a material effect on our consolidated results of operations or financial condition.

We have discussed the selection and application of these accounting estimates with the Audit Committee of the Board of Directors and our independent registered public accounting firm. It is management s view that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions. The sections below contain information about our most critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop the estimates.

Revenue Recognition and Accounting for Energy Trading and Marketing Activities

Nature of Estimates Required. Accounting standards require an accrual model to be used to account for our revenues from the sale of energy, capacity and ancillary services. We recognize revenue when it has been earned and collection is probable as a result of electricity delivered or capacity available to customers pursuant to contractual commitments that specify volume, price and delivery requirements. Sales of energy primarily are based on economic dispatch, or they may be as-ordered by an ISO or RTO, based on member participation agreements, but without an underlying contractual commitment. ISO and RTO revenues and revenues for sales of energy based on economic dispatch are recorded on the basis of MWh delivered, at the relevant day-ahead or real-time prices. Sales that have been delivered but not billed by period end are estimated. The accrual model is also used to account for our revenues from the sales of natural gas. These sales are sold at market-based prices through third party contracts. Sales that have been delivered but not billed by period end are estimated.

Accounting standards require a fair value model to be used to measure fair value on a recurring basis for derivative energy contracts that are used to manage our exposure to commodity price risk or that are used in our proprietary trading and fuel oil management activities. We use a variety of derivative financial instruments, such as futures, forwards, swaps and option contracts, in the management of our business. Such derivative financial instruments have varying terms and durations, or tenors, which range from a few days to a number of years, depending on the instrument.

Derivative financial instruments are recorded in our consolidated financial statements at fair value as either derivative contract assets or derivative contract liabilities, with changes in fair value recognized currently in income unless we have elected to apply cash flow hedging or they qualify for a scope exception pursuant to the accounting guidance. Management considers fair value techniques and valuation adjustments related to credit and liquidity to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors. Transactions that are not accounted for using the fair value model under the accounting guidance for derivative financial instruments are either not derivatives or qualify for the scope exception and are accounted for under accrual accounting. We recognize immediately in income inception gains and losses for transactions at other than the bid price or ask price.

Key Assumptions and Approach Used. In determining fair value, we generally use a market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. The fair value measurement inputs we use vary from readily observable prices for exchange-traded and over-the-counter instruments (Level 1 or Level 2) to price curves that cannot be validated through external pricing sources (Level 3). Note 4 to our consolidated financial statements explains the fair value hierarchy. For most delivery locations and tenors where we have positions, we receive multiple independent broker price quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of our derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for our assets and ask prices for liabilities. If no active market exists, we estimate the fair value of certain derivative financial instruments using price extrapolation, interpolation and other quantitative methods. We have not identified any distressed market conditions that would alter our valuation techniques at December 31, 2010. Fair value estimates involve uncertainties and matters of significant judgment. Our techniques for fair value estimation include assumptions for market prices, correlation and volatility. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. Our assets and liabilities classified as Level 3 in the fair value hierarchy represent approximately 3% of our total assets and 9% of our total liabilities measured at fair value at December 31, 2010.

The fair value of derivative contract assets and liabilities in our consolidated balance sheets is also affected by our assumptions as to time value, credit risk and non-performance risk. The nominal value of the contracts is discounted using a forward interest rate curve based on LIBOR. In addition, the fair value of our derivative contract assets is reduced to reflect the estimated default risk of counterparties on their contractual obligations to us. The default risk of our counterparties for a significant portion of our overall net position is measured based on published spreads on credit default swaps. The fair value of our derivative contract liabilities is reduced to reflect our estimated risk of default on our contractual obligations to counterparties and is measured based on published default rates of our debt. The credit risk reflected in the fair value of our derivative contract assets and the non-performance risk reflected in the fair value of our derivative contract liabilities are calculated with consideration of our master netting agreements with counterparties and our exposure is reduced by cash collateral posted to us against these obligations.

Effect if Different Assumptions Used. The amounts recorded as revenue or cost of fuel, electricity and other products change as estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control. Because we use derivative financial instruments and have not elected cash flow or fair value hedge accounting for the majority of our derivative financial instruments, certain components of our financial statements, including gross margin, operating income and balance sheet ratios, are at times volatile and subject to fluctuations in value primarily as a result of changes in forward energy and fuel prices. Significant negative changes in fair value could require us to post additional collateral either in the form of cash or letters of credit. Because the fair value measurements of our material assets and liabilities are based on observable market information, there is not a significant range of values around the fair value estimate. For our derivative financial instruments that are measured at fair value using quantitative pricing models, a significant change in estimate could affect our results of operations and cash flows at the time contracts are ultimately settled. The estimated fair value of our derivative contract assets and liabilities was a net asset of $720 million at December 31, 2010. A 10% change in electricity and fuel prices would result in approximately a $203 million change in the fair value of our net asset at December 31, 2010. See Item 7A, Quantitative and Qualitative Disclosures About Market Risk for further sensitivities in our assumptions used to calculate fair value. See note 4 to our consolidated financial statements for further information on derivative financial instruments related to energy trading and marketing activities.

Income Taxes and Deferred Tax Asset Valuation Allowance

Nature of Estimates Required. We currently record a tax provision for state and federal income taxes including any alternative minimum tax as applicable. We also recognize deferred tax assets and liabilities based on the difference between the balance sheet carrying amounts and the tax basis of the assets and liabilities. We must assess the likelihood that our deferred tax assets will be recoverable based on expected future taxable income. To the extent that we determine it is more-likely-than-not (greater than a 50% probability) that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. See note 7 to our consolidated financial statements for additional information regarding our deferred tax assets and the application of a valuation allowance to our NOLs.

Key Assumptions and Approach Used. Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. We think that the realization of future taxable income sufficient to utilize existing deferred tax assets is not more-likely-than not at this time. The primary factors related to this conclusion are as follows:

- The prices for power and natural gas remain low compared to several years ago and the effect of these lower prices on the projected gross margin.

- Current weak economic conditions and various demand-response programs have resulted in a decrease in the forecasted gross margin of our generating facilities.

- The estimated cash flows from contracts in place that hedge economically a portion of our portfolio for future periods are less than the contribution to our gross margin from historical realized value of hedges in recent years.

At December 31, 2010, our deferred tax assets reduced by the valuation allowance are completely offset by our deferred tax liabilities. Additionally, our valuation allowance includes $17 million relating to the tax effects of other comprehensive income items primarily related to employee benefits. These other comprehensive income items will be reduced in the event that the valuation allowance is no longer required.

Under the accounting guidance for the uncertainty of income taxes, we must reflect in our income tax provision the full benefit of all positions that will be taken in our income tax returns, except to the extent that such positions are uncertain and fall below the recognition requirements of the guidance. In the event that we determine that a tax position meets the uncertainty criteria, an additional liability or an adjustment to our NOLs, determined under the measurement criteria of the guidance will result. This liability or adjustment is referred to as an unrecognized tax benefit. We periodically reassess the tax positions reflected in our tax returns for open years based on the latest information available and determine whether any portion of the tax benefits reflected therein should be treated as unrecognized. The amount of the unrecognized tax benefit requires management to make significant assumptions about the expected outcomes of certain tax positions included in our filed or yet to be filed tax returns.

Effect if Different Assumptions Used. As a result of the Merger, each of Mirant and RRI Energy has separately determined whether or not each had experienced an ownership change as defined in the IRC. IRC Section (IRC §) 382 provides, in general, that an ownership change occurs when there is a greater than 50-percentage point increase in ownership of a company s stock by new or existing stockholders who own (or are deemed to own under IRC § 382) 5% or more of the loss company s stock over a three year testing period. IRC § 382 limits the amount of pre-merger NOLs that can be used during any post-ownership change year to offset taxable income. We have determined that RRI Energy did not experience an ownership change as defined above. Prior to the Merger, RRI Energy received guidance from the Internal Revenue Service that specifies the methodology to be used in determining whether an ownership change has occurred under circumstances when a stockholder owns interests in each of the merging companies immediately prior to the Merger. Our analysis concluded that sufficient overlapping stockholders of Mirant and RRI Energy existed immediately prior to the Merger such that the Merger did not cause an ownership change for RRI Energy. Therefore, RRI Energy s pre-merger NOLs have not been adjusted for any IRC § 382 limitation. Mirant experienced an ownership change as a result of the Merger. We have reduced the amount of the Mirant NOLs available to offset post-merger taxable income based on the limits determined in accordance with IRC § 382.

We continue to be under audit for multiple years by taxing authorities in various jurisdictions. Considerable judgment is required to determine the tax treatment of particular items that involve interpretations of complex tax laws. A tax liability is recorded for filing positions with respect to which the outcome is uncertain and the recognition criteria under the accounting guidance for uncertainty in income taxes has been met. Such liabilities are based on judgment and it can take many years to resolve a recorded liability such that the related filing position is no longer subject to question. We have not recorded a liability for those proposed tax adjustments related to the current tax audits where we continue to think that our filing position meets the more-likely-than-not threshold prescribed in the accounting guidance related to accounting for uncertainty in income taxes. Any adverse outcomes arising from these matters could result in a material change in the amount of our deferred taxes.

Long-Lived Assets

Estimated Useful Lives

Nature of Estimates Required. The estimated useful lives of our long-lived assets are used to compute depreciation expense, determine the carrying value of asset retirement obligations and estimate expected future cash flows attributable to an asset for the purposes of impairment testing. Estimated useful lives are based, in part, on the assumption that we provide an appropriate level of capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly.

Key Assumptions and Approach Used. Estimated useful lives are the mechanism by which we allocate the cost of long-lived assets over the asset s service period. We perform depreciation studies periodically to update changes in estimated useful lives. The actual useful life of an asset could be affected by changes in estimated or actual commodity prices, environmental regulations, various legal factors, competitive forces and our liquidity and ability to sustain required maintenance expenditures and satisfy asset retirement obligations.

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We use composite depreciation for groups of similar assets and establish an average useful life for each group of related assets. In accordance with the accounting guidance related to evaluating long-lived assets for impairment, we cease depreciation on long-lived assets classified as held for sale. Also, we may revise the remaining useful life of an asset held and used subject to impairment testing. See note 5 to our consolidated financial statements for additional information related to our property, plant and equipment.

We completed a depreciation study in the first quarter of 2010 for the legacy Mirant generating facilities that resulted in a change to the estimated useful lives of its long-lived assets. The change in useful lives resulted in an increase of approximately $2 million in depreciation and amortization expense during 2010. In addition, the change in useful lives also resulted in an increase of $9 million in asset retirement obligations and a corresponding increase of $9 million in property, plant and equipment, net at December 31, 2010.

Effect if Different Assumptions Used. The determination of estimated useful lives is dependent on subjective factors such as expected market conditions, commodity prices and anticipated capital expenditures. Since composite depreciation rates are used, the actual useful life of a particular asset may differ materially from the useful life estimated for the related group of assets. A 10% increase in the weighted average useful lives of our facilities would result in a $32 million decrease in annual depreciation expense. A 10% decrease in the weighted average useful lives of our facilities would result in a $39 million increase in annual depreciation expense. In the event the useful lives of significant assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities recognized for future asset retirement obligations may be insufficient and impairments in the carrying value of tangible and intangible assets may result.

Asset Retirement Obligations

Nature of Estimates Required. We account for asset retirement obligations under the accounting guidance for asset retirement obligations and conditional asset retirements. This guidance requires an entity to recognize the fair value of a liability for conditional and unconditional asset retirement obligations in the period in which they are incurred. Retirement obligations associated with long-lived assets included within the scope of the accounting guidance are those obligations for which a requirement exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Asset retirement obligations are estimated using the estimated current cost to satisfy the retirement obligation, increased for inflation through the expected period of retirement and discounted back to present value at our credit-adjusted risk free rate. We have identified certain asset retirement obligations within our power generating operations and have a noncurrent liability of $128 million recorded at December 31, 2010. These asset retirement obligations are primarily related to asbestos abatement at some of our generating facilities, the removal of oil storage tanks, equipment on leased property and environmental obligations related to the closing of ash disposal sites.

During 2010, a third-party consulting firm completed a study on behalf of the Company to determine the extent of asbestos present at certain of our generating facilities. The consulting firm also provided us with cost estimates for the removal of the asbestos. As a result, we revised the cost estimates associated with our asset retirement obligations for asbestos removal at all of our generating facilities.

Key Assumptions and Approach Used. The fair value of liabilities associated with the initial recognition of asset retirement obligations is estimated by applying a present value calculation to current engineering cost estimates of satisfying the obligations. Significant inputs to the present value calculation include current cost estimates, estimated asset retirement dates and appropriate discount rates. Where appropriate, multiple cost and/or retirement scenarios have been probability weighted.

Effect if Different Assumptions Used. We update liabilities associated with asset retirement obligations as significant assumptions change or as relevant new information becomes available.

Asset Impairments

Nature of Estimates Required. We evaluate our long-lived assets, including intangible assets, for impairment in accordance with applicable accounting guidance. The amount of an impairment charge is calculated as the excess of the asset s carrying value over its fair value, which generally represents the discounted expected future cash flows attributable to the asset, or in the case of an asset we expect to sell, at its fair value less costs to sell.

The accounting guidance related to impairments of long-lived assets requires management to recognize an impairment charge if the sum of the undiscounted expected future cash flows from a long-lived asset or definite-lived intangible asset is less than the carrying value of that asset. We evaluate our long-lived assets (property, plant and equipment) and definite-lived intangible assets for impairment whenever indicators of impairment exist or when we commit to sell the asset. These evaluations of long-lived assets and definite-lived intangible assets may result from significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operational analyses. If the carrying amount is not recoverable, an impairment charge is recorded.

The prices for power and natural gas remain low compared to several years ago. The energy gross margin from our baseload coal units is negatively affected by these price levels. Additionally, the current weak economic conditions and various demand-response programs have resulted in a decrease in the forecasted gross margin of our generating facilities. On an ongoing basis, we evaluate our long-lived assets for indications of impairment; however, given the remaining useful lives for many of our generating facilities, the total undiscounted cash flows for these generating facilities are more significantly affected by the long-term view of supply and demand than by the short term fluctuations in energy prices and demand. As such, we typically do not consider short term decreases in either energy prices or demand to cause an impairment evaluation. Our current expectation is that there will be a recovery in gross margins over time as a result of declining reserve margins in the markets in which we operate such that companies constructing new generating facilities can earn a reasonable rate of return on their investment. This implies that gross margins and therefore cash flows in the future will be better than they are currently because market prices will need to rise high enough to provide an incentive for new generating facilities to be built and the entire market will realize the benefit of those higher gross margins.

Key Assumptions and Approach Used. The impairment evaluation is a two-step process, the first of which involves comparing the undiscounted cash flows to the carrying value of the asset. If the carrying value exceeds the undiscounted cash flows, the fair value of the asset must be calculated on a discounted basis. The fair value of an asset is the price that would be received from a sale of the asset in an orderly transaction between market participants at the measurement date. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, when available. In the absence of quoted prices for identical or similar assets, fair value is estimated using various internal and external valuation methods. These methods include discounted cash flow analyses and reviewing available information on comparable transactions. The determination of fair value requires management to apply judgment in estimating future capacity and energy prices, environmental and maintenance expenditures and other cash flows. Our estimates of the fair value of the assets include significant assumptions about the timing of future cash flows, remaining useful lives and the selection of a discount rate that represents the estimated weighted average cost of capital consistent with the risk inherent in future cash flows.

Our long-lived asset impairment assessments typically include assumptions about the following:

- electricity, fuel and capacity prices;
- costs related to compliance with environmental regulations;

timing of announced transmission projects;

timing and extent of generating capacity additions and retirements; and

future capital expenditure requirements related to the generating facilities.

2010

GenOn Mid-Atlantic Generating Facilities We have goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet, which is eliminated upon consolidation at GenOn North America. In accordance with accounting guidance for goodwill and other intangible assets, we are required to test the goodwill balance at GenOn Mid-Atlantic at least annually. We performed the goodwill assessment at October 31, 2010, which, by policy, is our annual testing date. In conducting step one of the goodwill impairment analysis for GenOn Mid-Atlantic, we noted that the carrying value of its net assets exceeded the calculated fair value of GenOn Mid-Atlantic, indicating that step two of the goodwill impairment analysis was required. Based on the results of the step one goodwill impairment analysis, we tested GenOn Mid-Atlantic s long-lived assets for impairment under the accounting guidance related to impairment of long-lived assets before completion of the step two test for goodwill.

Upon completion of the assessment, we determined that none of the GenOn Mid-Atlantic generating facilities were impaired at October 31, 2010.

In December 2010, PJM published an updated load forecast, which depicted a decrease in the expected demand from prior projections because of lower economic growth expectations. As a result of the load forecast, our current expectation is that there will be a decrease in the clearing prices for future capacity auctions in certain years. The decrease in projected capacity revenue caused us to update our October 2010 impairment review of GenOn Mid-Atlantic s long-lived assets. The sum of the updated December 2010 undiscounted cash flows for the Chalk Point and Morgantown generating facilities exceeded their carrying values, which represented approximately 23% and 17% of our total property, plant and equipment, net at December 31, 2010. However, we determined that the Dickerson and Potomac River generating facilities were impaired at December 31, 2010, as the carrying values exceeded the updated December 2010 undiscounted cash flows. We recorded fourth quarter impairment losses of $523 million and $42 million on our consolidated statement of operations to reduce the carrying values of the Dickerson and Potomac River generating facilities, respectively, to their estimated fair values. In addition, as a result of the full impairment of the Potomac River generating facility, we recorded $32 million in operations and maintenance expense and corresponding liabilities associated with our commitment to reduce particulate emissions at our Potomac River generating facility as part of the agreement with the City of Alexandria, Virginia. The planned capital investment would not be recovered in future periods based on the current projected cash flows of the Potomac River generating facility.

Our assumptions related to future electricity and fuel prices were based on observable market prices to the extent available and long-term prices derived from proprietary fundamental market modeling. The long-term capacity prices were based on the assumption that the PJM RPM capacity market would continue to be consistent with the current structure. For the Dickerson generating facility, the total CO_2 costs under the levy were determined by applying the cost of CO_2 emissions to the expected generation forecasts. Our estimate of future cash flows related to the Dickerson generating facility involved considering scenarios related to the Montgomery County levy. The scenarios are related to the success of the legal challenges to the law. We also assumed that a federal CO_2 cap-and-trade program would be instituted later this decade which would supplant all pre-existing CO_2 programs, including the Montgomery County levy. In addition, our assumptions included costs associated with compliance of other environmental regulations. There are several transmission projects currently planned in the Mid-Atlantic region, including the Trans-Allegheny Interstate Line (TrAIL), Mid-Atlantic Power Pathway transmission line (MAPP) and the Potomac-Appalachian transmission line (PATH). The assumptions regarding the timing of these projects were based on the current status of permitting and construction of each project. The assumptions regarding electricity demand were based on forecasts from PJM and assumptions for generating capacity additions and retirements included publicly-announced projects, which take into account renewable sources of electricity. Capital expenditures include the remaining contract retention payments for the completion of the Maryland Healthy Air Act pollution control equipment for our Maryland generating facilities. For our Potomac River generating facility, the cash flows also include the remaining $32 million that GenOn Potomac River committed to spend to reduce particulate emissions as part of the agreement with the City of Alexandria, Virginia.

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The estimates and assumptions used in the impairment analyses of the GenOn Mid-Atlantic generating facilities are subject to a high degree of uncertainty, and changes in these assumptions could affect the amount of the impairment loss or result in additional future impairment losses. A decrease in projected electricity prices or an increase in coal prices would decrease the future cash flows of the GenOn Mid-Atlantic generating facilities. Additionally, decreases in the projected demand or changes to the structure of the PJM RPM capacity market could negatively affect the future capacity prices the facilities will earn. The assumptions include the development of a potential federal cap-and-trade program for CO_2 emissions. If we are not compensated for the costs of complying with a federal CO_2 program through allocated CO_2 allowances, increased electricity and capacity prices or decreased coal prices, the cash flows of the GenOn Mid-Atlantic generating facilities would be negatively affected. In addition, if pre-existing CO_2 emission programs such as the RGGI and the Montgomery County levy are allowed to remain in effect under a federal CO_2 program, the cash flows of the GenOn Mid-Atlantic generating facilities would be negatively affected. If the planned transmission projects are completed earlier than assumed, this could negatively affect the cash flows of the facilities. Also, changes in assumptions regarding generating capacity additions and retirements in the PJM region could affect the cash flows, depending on the timing and extent of additions and retirements. The assumptions include only those capital expenditures needed to keep the plants operational through their estimated remaining useful lives. However, changes in laws or regulations could require additional capital investments beyond amounts forecasted to keep the plants operational.

The estimates of future cash flows did not include contracts entered into to hedge economically the expected generation of GenOn Mid-Atlantic s generating facilities. The cash flows related to these contracts were excluded because they were not directly attributable to each of the generating facilities.

For purposes of impairment testing, a long-lived asset or assets must be grouped at the lowest level of independent identifiable cash flows. Each generating facility was determined to be its own group, which included the leasehold improvements for the leased generating units at the Dickerson and Morgantown generating facilities. See note 5(c) to our consolidated financial statements for further information related to our GenOn Mid-Atlantic impairment analyses.

Dickerson Generating Facility We also reviewed our Dickerson generating facility for impairment in the second quarter of 2010 upon the enactment of the CO_2 levy by the Montgomery County Council. Upon completion of the assessment, we determined that the Dickerson generating facility was not impaired in the second quarter of 2010.

Bowline Generating Facility During the second quarter of 2010, the NYISO issued its annual peak load and energy forecast in its Gold Book. The Gold Book reports projected electricity supply and demand for the New York control area for the next ten years. The most recent Gold Book projects a significant decrease in future electricity demand as a result of current economic conditions and the expected future effects of demand-side management programs in New York. The expected reduction in future demand as a result of demand-side management programs is being driven primarily by an energy efficiency program being instituted within the State of New York that will seek to achieve a 15% reduction from 2007 energy volumes by 2015. As a result of the projections in the Gold Book, we evaluated the Bowline generating facility for impairment in the second quarter of 2010. The sum of the probability weighted undiscounted cash flows for the Bowline generating facility exceeded the carrying value. As a result, we did not record an impairment loss for the Bowline generating facility during the second quarter of 2010.

GenOn Bowline has challenged its property tax assessment for the 2009 and 2010 tax years. Although the assessment for the 2010 tax year was reduced significantly from the assessment received in 2009, the assessment continues to exceed significantly the estimated fair value of the generating facility.

In the fourth quarter of 2010, we identified certain operational issues that reduced the available capacity of the Bowline generating facility. We are in the process of evaluating long-term solutions for the generating facility, but our current expectation is that the reduction in available capacity could extend through 2012. In the fourth quarter of 2010, we again evaluated the Bowline generating facility for impairment because of the expected extended reduction in available capacity together with the pending property tax litigation and the effect of supply and demand assumptions in the NYISO s Gold Book. The sum of the probability weighted undiscounted cash flows for the Bowline generating facility exceeded the carrying value. Therefore, we did not record an impairment loss for the Bowline generating facility during 2010. The carrying value of the Bowline generating facility represented approximately 2% of our total property, plant and equipment, net at December 31, 2010. See note 5(c) to our consolidated financial statements for further information related to our impairment analysis of the Bowline generating facility.

Emissions Allowances In August 2010, the EPA proposed a replacement for the CAIR. The market prices for SO_2 and NO_x emissions allowances declined as a result of the proposed rule. Our historical accounting policy has been to include emissions allowances in our asset groupings when evaluating long-lived assets for impairment. However, to the extent the final EPA rule significantly modifies or ends the current cap-and-trade program, we may evaluate whether our SO_2 and NO_x emissions allowances included in property, plant and equipment and intangible assets should be evaluated separately from the underlying generating facilities. The carrying value of the SO_2 and NO_x emissions allowances included in property, plant and equipment and intangible assets at December 31, 2010 was $159 million. See Environmental Matters for further information on the EPA s proposed replacement of the CAIR.

2009

Potrero Generating Facility In the third quarter of 2009, GenOn Potrero executed a settlement agreement with the City and County of San Francisco in which it agreed to shut down the Potrero generating facility when it is no longer needed for reliability, as determined by the CAISO. That settlement agreement became effective in November 2009. In December 2010, the CAISO provided GenOn Potrero with the requisite notice of termination of the RMR agreement. On January 19, 2011, at the request of GenOn Potrero, the FERC approved changes to GenOn Potrero s RMR agreement to allow the CAISO to terminate the RMR agreement effective February 28, 2011. On February 28, 2011, the Potrero facility was shut down. The Potrero generating facility was fully depreciated at December 31, 2010.

The asset group for GenOn Potrero included intangible assets recorded at GenOn California North related to trading rights and development rights. As a result of certain terms included in the settlement agreement, we separately evaluated the trading and development rights associated with the Potrero generating facility for impairment and determined that both of these intangible assets were fully impaired as of September 30, 2009. Accordingly, we recognized an impairment loss of $9 million on our consolidated statement of operations to write off the carrying value of the intangible assets related to the Potrero generating facility. See note 5(c) to our consolidated financial statements for further information related to our impairment analysis of the Potrero generating facility and related intangible assets.

Contra Costa Generating Facility On September 2, 2009, GenOn Delta entered into an agreement with PG&E for the 674 MW at Contra Costa units 6 and 7 for the period from November 2011 through April 2013. At the end of the agreement, and subject to any necessary regulatory approval, GenOn Delta has agreed to retire Contra Costa units 6 and 7, which began operations in 1964, in furtherance of state and federal policies to retire aging power plants that utilize once-through cooling technology. We evaluated the trading rights related to GenOn Delta s Contra Costa generating facility for impairment during the third quarter of 2009 as a result of the retirement provisions in the tolling agreement. Because the Contra Costa generating facility is under contract with PG&E through the expected shutdown date, we determined the intangible asset was fully impaired as of September 30, 2009. We recorded an impairment loss of $5 million on our consolidated statement of operations to write off the carrying value of the trading rights related to the Contra Costa generating facility.

Canal Generating Facility Our 1,126 MW Canal generating facility is located in the lower SEMA load zone in the ISO-NE control area. ISO-NE previously has determined that, at times, it is necessary for the Canal generating facility to operate to meet local reliability criteria for SEMA when it is not economic for the Canal generating facility to operate based upon prevailing market prices. When the Canal generating facility operates to meet local reliability criteria, we are compensated at the price we bid into the ISO-NE, pursuant to ISO-NE market rules, rather than at the market price.

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During 2009, NSTAR Electric Company completed planned upgrades to the SEMA transmission system. These upgrades are expected to reduce the need for the Canal generating facility to operate and caused a reduction in energy gross margin compared to historical levels. The final phase of these transmission upgrades was completed in the third quarter of 2009. With the completion of the transmission upgrades, we expect that the future revenues of the Canal generating facility will be principally capacity revenue from ISO-NE forward capacity market. Our current projections indicate that the undiscounted cash flows exceed the carrying value of the facility at December 31, 2009. As a result, we did not record an impairment charge because of the transmission upgrades. We continue to monitor developments related to our Canal generating facility, including the NPDES and SWD Permit. See Item 1. Business Environmental Regulation for further information related to the NPDES and SWD Permit for the Canal generating facility. The carrying value of the Canal generating facility represented approximately 3% of our total property, plant and equipment, net at December 31, 2010.

GenOn Mid-Atlantic Generating Facilities We have goodwill recorded at our GenOn Mid-Atlantic registrant on its standalone balance sheet, which is eliminated upon consolidation at GenOn North America. In accordance with accounting guidance for goodwill and other intangible assets, we are required to test the goodwill balance at GenOn Mid-Atlantic at least annually. We performed the goodwill assessment at October 31, 2009, which, by policy, is our annual testing date. In conducting step one of the goodwill impairment analysis for GenOn Mid-Atlantic, we noted that the carrying value of its net assets exceeded the calculated fair value of GenOn Mid-Atlantic, indicating that step two of the goodwill impairment analysis was required. Based on the results of the step one goodwill impairment analysis, we tested GenOn Mid-Atlantic s long-lived assets for impairment under the accounting guidance related to impairment of long-lived assets before completion of the step two test for goodwill. During 2009, the continued decline in average natural gas prices caused power prices to decline in the Eastern PJM region. Additionally, weak economic conditions and various demand-response programs have resulted in a decrease in the forecasted gross margin of the GenOn Mid-Atlantic generating facilities.

Upon completion of our assessment, which was based on the accounting guidance related to the impairment of long-lived assets, we determined that the Potomac River generating facility was impaired, as the carrying value exceeded the undiscounted cash flows. We recorded an impairment loss of $207 million on our consolidated statement of operations to reduce the carrying value of the Potomac River generating facility to its estimated fair value. In performing our impairment assessment, we noted that the undiscounted cash flows for other GenOn Mid-Atlantic generating facilities also decreased significantly from the prior year. We determined that no other GenOn Mid-Atlantic long-lived assets were impaired at October 31, 2009.

2008

GenOn Mid-Atlantic Generating Facilities We performed the goodwill assessment for GenOn Mid-Atlantic at October 31, 2008, which, by policy, is our annual testing date. In conducting step one of the goodwill impairment analysis for GenOn Mid-Atlantic, we noted that the carrying value of its net assets exceeded the calculated fair value of GenOn Mid-Atlantic, indicating that step two of the goodwill impairment analysis was required. Based on the results of the step one goodwill impairment analysis, we tested GenOn Mid-Atlantic s long-lived assets for impairment under the accounting guidance related to impairment of long-lived assets before completion of the step two test for goodwill. Upon completion of our assessment, which was based on the accounting guidance related to the impairment of long-lived assets, we determined that no further analysis of the long-lived assets was needed at December 31, 2008.

Effect if Different Assumptions Used. The estimates and assumptions used to determine whether an impairment exists are subject to a high degree of uncertainty. The estimated fair value of an asset would change if different estimates and assumptions were used in our applied valuation techniques, including estimated undiscounted cash flows, discount rates and remaining useful lives for assets held and used. If actual results are not consistent with the assumptions used in estimating future cash flows and asset fair values, we may be exposed to additional losses that could be material to our results of operations.

See note 5(c) to our consolidated financial statements for additional information on impairments.

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Loss Contingencies

Nature of Estimates Required. We record loss contingencies when it is probable that a liability has been incurred and the amount can be reasonably estimated. We consider loss contingency estimates to be critical accounting estimates because they entail significant judgment regarding probabilities and ranges of exposure, and the ultimate outcome of the proceedings is unknown and could have a material adverse effect on our results of operations, financial condition and cash flows. We currently have loss contingencies related to litigation, environmental matters, tax matters and others.

Key Assumptions and Approach Used. The determination of a loss contingency requires significant judgment as to the expected outcome of each contingency in future periods. In making the determination as to potential losses and probability of loss, we consider all available positive and negative evidence including the expected outcome of potential litigation. We record our best estimate of a loss, or the low end of our range if no estimate is better than another estimate within a range of estimates, when the loss is considered probable. As additional information becomes available, we reassess the potential liability related to the contingency and revise our estimates. In our evaluation of legal matters, management holds discussions with applicable legal counsel and relies on analysis of case law and legal precedents.

Effect if Different Assumptions Used. Revisions in our estimates of potential liabilities could materially affect our results of operations and the ultimate resolution may be materially different from the estimates that we make.

See notes 2, 7, 10, 18 and 19 to our consolidated financial statements for additional information on our loss contingencies.

Litigation

We are currently involved in legal proceedings. We estimate the range of liability through discussions with applicable legal counsel and analysis of case law and legal precedents. We record our best estimate of a loss, or the low end of our range if no estimate is better than another estimate within a range of estimates, when the loss is considered probable and can be reasonably estimated. As additional information becomes available, we reassess the potential liability related to our pending litigation and revise our estimates. Revisions in our estimates of the potential liability could materially affect our results of operations and the ultimate resolution may be materially different from the estimates that we make.

See note 18 to our consolidated financial statements for further information related to our legal proceedings.

Recently Adopted Accounting Guidance

See note 1 to our consolidated financial statements for further information related to our recently adopted accounting guidance.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Fair Value Measurements

We are exposed to market risk, primarily associated with commodity prices. We also consider risks associated with interest rates and credit when valuing our derivative financial instruments.

The estimated net fair value of our derivative contract assets and liabilities was a net asset of $720 million and $702 million at December 31, 2010 and 2009, respectively. The following tables provide a summary of

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the factors affecting the change in fair value of the derivative contract asset and liability accounts for 2009 and 2010, respectively:

	Commodity Contracts		Other Contracts	
	Asset Management	Trading	Interest Rate	Total
	(in millions)			
Fair value of portfolio of assets and liabilities at January 1, 2009	$ 549	$ 106	$	$ 655
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value(1)	20	(150)		(130)
Roll off of previous values(2)	(539)	(100)		(639)
Purchases, issuances and settlements(3)	671	145		816
Fair value of portfolio of assets and liabilities at December 31, 2009	701	1		702
Derivative contracts acquired and/or assumed in the Merger	49			49
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value(1)	169	66	19	254
Roll off of previous values(2)	(340)	(49)		(389)
Purchases, issuances and settlements(3)	127	(23)		104
Fair value of portfolio of assets and liabilities at December 31, 2010	$ 706	$ (5)	$ 19	$ 720

(1) The fair value, as of the end of each quarterly reporting period, of contracts entered into during each quarterly reporting period and the gains or losses attributable to contracts that existed as of the beginning of each quarterly reporting period and were still held at the end of each quarterly reporting period.

(2) The fair value, as of the beginning of each quarterly reporting period, of contracts that settled during each quarterly reporting period.

(3) Denotes cash settlements during each quarterly reporting period of contracts that existed at the beginning of each quarterly reporting period.

In May 2010, we concluded that we could no longer assert that physical delivery is probable for many of our coal agreements. The conclusion was based on expected generation levels, changes observed in the coal markets and substantial progress in the construction of a coal blending facility at the Morgantown generating facility that will allow for greater flexibility of our coal supply. Because we can no longer assert that physical delivery of coal from these agreements is probable, we are required to apply fair value accounting for these contracts in the current period and prospectively. The fair value of these derivative contracts is included in the tables above.

We did not elect the fair value option for any financial instruments under the accounting guidance. However, we do transact using derivative financial instruments which are required to be recorded at fair value in our consolidated balance sheets under the accounting guidance related to derivative financial instruments.

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At December 31, 2010, the estimated net fair value of our derivative contract assets and liabilities are (asset (liability)):

Sources of Fair Value	2011	2012	2013	2014 (in millions)	2015	2016 and thereafter	Total fair value
Asset Management:							
Prices actively quoted (Level 1)	$ (19)	$ (6)	$	$	$	$	$ (25)
Prices provided by other external sources (Level 2)	253	173	184	191			801
Prices based on models and other valuation methods (Level 3)	(38)	(36)	4				(70)
Total asset management	$ 196	$ 131	$ 188	$ 191	$	$	$ 706
Trading Activities:							
Prices actively quoted (Level 1)	$ 3	$ (6)	$	$	$	$	$ (3)
Prices provided by other external sources (Level 2)	(8)	4					(4)
Prices based on models and other valuation methods (Level 3)	2						2
Total trading activities	$ (3)	$ (2)	$	$	$	$	$ (5)
Interest Rate:							
Prices actively quoted (Level 1)	$	$	$	$	$	$	$
Prices provided by other external sources (Level 2)			(1)	(1)	2	19	19
Prices based on models and other valuation methods (Level 3)							
Total interest rate	$	$	$ (1)	$ (1)	$ 2	$ 19	$ 19

The fair values shown in the table above are subject to significant changes as a result of fluctuating commodity forward market prices, volatility and credit risk. For further discussion of how we determine these fair values, see note 4 to our consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operations Recently Adopted Accounting Guidance and Critical Accounting Estimates Critical Accounting Estimates in Item 7 of this Form 10-K.

Commodity Price Risk

In connection with our business of generating electricity, we are exposed to energy commodity price risk associated with the acquisition of fuel and emissions allowances needed to generate electricity, the price of electricity produced and sold and the fair value of our fuel inventories. A portion of our fuel requirements is purchased in the spot market and a portion of the electricity we produce is sold in the spot market. In addition, the open positions in our proprietary trading and fuel oil management activities expose us to risks associated with changes in energy commodity prices.

As a result, our financial performance varies depending on changes in the prices of energy and energy-related commodities. See Item 7, Critical Accounting Estimates for a discussion of the accounting treatment for asset management, proprietary trading and fuel oil management activities.

The financial performance of our business of generating electricity is influenced by the difference between the variable cost of converting a fuel, such as natural gas, coal or oil, into electricity, and the variable revenue we receive from the sale of that electricity. The difference between the cost of a specific fuel used to generate one MWh of electricity and the market value of the electricity generated is commonly referred to as the conversion spread. Absent the effects of our derivative contract activities, the operating margins that we realize are equal to the difference between the aggregate conversion spread and the cost of operating the facilities that produce the electricity sold.

Conversion spreads are dependent on a variety of factors that influence the cost of fuel and the sales price of the electricity generated over the longer term, including conversion spreads of other generating facilities in the regions in which we operate, facility outages, weather and general economic conditions. As a result of these influences, the cost of fuel and electricity prices do not always change in the same magnitude or direction, which results in conversion spreads for a particular generating facility widening or narrowing (or becoming negative) over any given period.

Through our asset management activities, we enter into a variety of exchange-traded and OTC energy and energy-related derivative financial instruments, such as forward contracts, futures contracts, option contracts and financial swap agreements, to manage our exposure to commodity price risks. These contracts have varying terms and durations which range from a few days to years, depending on the instrument. Our proprietary trading activities also utilize similar derivative contracts in markets where we have a physical presence to attempt to generate incremental gross margin. Our fuel oil management activities use derivative financial instruments to hedge economically the fair value of our physical fuel oil inventories, optimize the approximately three million barrels of storage capacity that we own or lease, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products.

Derivative energy contracts that are required to be reflected at fair value are presented as derivative contract assets and liabilities in the consolidated balance sheets. The net changes in their fair market values are recognized in income in the period of change. The determination of fair value considers various factors, including closing exchange or OTC market price quotations, time value, credit quality, liquidity and volatility factors underlying options. See Item 7, Critical Accounting Estimates for the accounting treatment of asset management, proprietary trading and fuel oil management activities.

Counterparty Credit Risk

The valuation of our derivative contract assets is affected by the default risk of the counterparties with which we transact. We recognized a reserve, which is reflected as a reduction of our derivative contract assets, related to counterparty credit risk of $21 million and $13 million at December 31, 2010 and 2009, respectively.

In accordance with the fair value measurements accounting guidance, we calculate the credit reserve through consideration of observable market inputs, when available. We calculate our credit reserve using published spreads, where available, or proxies based upon published spreads, on credit default swaps for our counterparties applied to our current exposure and potential loss exposure from the financial commitments in our risk management portfolio. We do not, however, transact in credit default swaps or any other credit derivative. Potential loss exposure is calculated as our current exposure plus a calculated VaR over the remaining life of the contracts.

Our non-collateralized power hedges entered into by GenOn Mid-Atlantic with financial institutions, which represent 42% of our net notional power position at December 31, 2010, are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties, and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. Our coal contracts included in derivative contract assets and liabilities in the consolidated balance sheets also do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in coal prices. An increase of 10% in the spread of credit default swaps of our trading partners would result in an increase of $2 million in our credit reserve at December 31, 2010.

Once we have delivered a physical commodity or agreed to financial settlement terms, we are subject to collection risk. Collection risk is similar to credit risk and collection risk is accounted for when we establish our provision for uncollectible accounts. We manage this risk using the same techniques and processes used in credit risk discussed above.

We also monitor counterparty credit concentration risk on both an individual basis and a group counterparty basis. See note 4(c) to our consolidated financial statements for further discussion of our counterparty credit concentration risk.

GenOn Credit Risk

In valuing our derivative contract liabilities, we apply a valuation adjustment for our non-performance which is based on the probability of our default. Our methodology incorporates published spreads on our credit default swaps, where available, or proxies based upon published spreads. An increase of 10% in the spread of our credit default swap rate would have an immaterial effect on our consolidated statement of operations for 2010.

Broker Quotes

The fair value of our derivative contract assets and liabilities is based largely on observable quoted prices from exchanges and unadjusted indicative quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. We think that these prices represent the best available information for valuation purposes. In determining the fair value of our derivative contract assets and liabilities, we use third-party market pricing where available. Note 4 to our consolidated financial statements explains the fair value hierarchy. Our transactions in Level 1 of the fair value hierarchy primarily consist of natural gas and crude oil futures traded on the NYMEX and swaps cleared against NYMEX prices. For these transactions, we use the unadjusted published settled prices on the valuation date. Our transactions in Level 2 of the fair value hierarchy primarily include non-exchange-traded derivatives such as OTC forwards, swaps and options, and certain energy derivative instruments that are cleared and settled through exchanges. We value these transactions using indicative quoted prices from independent brokers or other widely-accepted valuation methodologies. Transactions are classified in Level 2 if substantially all (greater than 90%) of the fair value can be corroborated using observable market inputs such as transactable broker quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of our derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for our assets and ask prices for liabilities. The quotes that we obtain from brokers are non-binding in nature, but are from brokers that typically transact in the market being quoted and are based on their knowledge of market transactions on the valuation date. We typically obtain multiple broker quotes on the valuation date for each delivery location that extend for the tenor of our underlying contracts. The number of quotes that we can obtain depends on the relative liquidity of the delivery location on the valuation date. If multiple broker quotes are received for a contract, we use an average of the quoted bid or ask prices. If only one broker quote is received for a delivery location and it cannot be validated through other external sources, we will assign the quote to a lower level within the fair value hierarchy. In some instances, we may combine broker quotes for a liquid delivery hub with broker quotes for the price spread between the liquid delivery hub and the delivery location under the contract. We also may apply interpolation techniques to value monthly strips if broker quotes are only available on a seasonal or annual basis. We perform validation procedures on the broker quotes at least on a monthly basis. The validation procedures include reviewing the quotes for accuracy and comparing them to our internal price curves. In certain instances, we may discard a broker quote if it is a clear outlier and multiple other quotes are obtained. At December 31, 2010, we obtained broker quotes for 100% of our delivery locations classified in Level 2 of the fair value hierarchy.

Inactive markets are considered to be those markets with few transactions, noncurrent pricing or prices that vary over time or among market makers. Our transactions in Level 3 of the fair value hierarchy may involve transactions whereby observable market data, such as broker quotes, are not available for substantially all of the tenor of the contract or we are only able to obtain indicative broker quotes that cannot be corroborated by observable market data. In such cases, we may apply valuation techniques such as extrapolation and other quantitative methods to determine fair value. Proprietary models may also be used to determine the fair value of certain of our derivative contract assets and liabilities that may be structured or otherwise

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tailored. Our techniques for fair value estimation include assumptions for market prices, correlation and volatility. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. At December 31, 2010, our assets and liabilities classified as Level 3 in the fair value hierarchy represented approximately 3% of our total assets and 9% of our total liabilities measured at fair value.

Value at Risk

Our risk management policy limits our trading to certain products and contains limits and restrictions related to our asset management, proprietary trading and fuel oil management activities.

We manage the price risk associated with asset management activities through a variety of methods. Our risk management policy requires that asset management activities are restricted to only those activities that are risk-reducing. We ensure compliance with this restriction at the transactional level by testing each individual transaction executed relative to the overall asset position.

We also use VaR to measure the market price risk of our energy asset portfolio as a result of potential changes in market prices. VaR is a statistical model that provides an estimate of potential loss. We calculate VaR based on the parametric variance/covariance approach, utilizing a 95% confidence interval and a one-day holding period on a rolling 24-month forward looking period. Additionally, we estimate correlation based on historical commodity price changes. Volatilities are based on a combination of historical price changes and implied market rates.

VaR is calculated quarterly on an asset management portfolio comprised of mark-to-market and non mark-to-market energy assets and liabilities, including generating facilities and bilateral physical and financial transactions. Asset management VaR levels are substantially reduced as a result of our decision to actively hedge economically in the forward markets the commodity price risk related to the expected generation and fuel usage of our generating facilities. See Item 1, Business Asset Management for discussion of our hedging strategies.

The following table summarizes year-end, average, high and low VaR for our asset management portfolio:

Asset Management VaR	**2010**	**2009**
	(in millions)	
Year-end	$ 26	$ 11
Average	$ 11	$ 12
High	$ 26	$ 13
Low	$ 5	$ 11

We calculate VaR daily on portfolios consisting of mark-to-market and non mark-to-market bilateral physical and financial transactions related to our proprietary trading activities and fuel oil management operations.

The following table summarizes year-end, average, high and low VaR for our proprietary trading and fuel oil management activities:

Proprietary Trading and Fuel Oil Management VaR	**2010**	**2009**
	(in millions)	
Year-end	$ 2	$ 2

Average	$ 2	$ 2
High	$ 3	$ 4
Low	$ 1	$ 1

Because of inherent limitations of statistical measures such as VaR and the seasonality of changes in market prices, the VaR calculation may not reflect the full extent of our commodity price risk exposure on our cash flows and liquidity. Additionally, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated VaR, and such changes could have a material effect on our financial results.

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Interest Rate Risk

Fair Value Measurement

We are also subject to interest rate risk when discounting to account for time value in determining the fair value of our derivative contract assets and liabilities. The nominal value of our derivative contract assets and liabilities is discounted using a LIBOR forward interest rate curve based on the tenor of our transactions. It is estimated that a one percentage point change in market interest rates would result in a change of $22 million to our derivative contract assets and a change of $8 million to our derivative contract liabilities at December 31, 2010.

Debt

Some of our debt is subject to variable interest rates, including our $698 million senior secured term loan and our $788 million senior secured revolving credit facility. Borrowings under these facilities will bear interest at the LIBOR rate plus a margin of 4.25% and 3.50% per annum, respectively. However, for the new term loan facility only, in no event shall the LIBOR rate be less than 1.75% per annum. We do not currently plan to enter into any interest rate swap agreements to mitigate the variable interest rate risk associated with our term loan facility or revolving credit facility. In the future, we may enter into interest rate swaps that involve the exchange of floating for fixed rate interest payments in order to reduce interest rate volatility. However, we may not maintain interest rate swaps with respect to all of our variable rate indebtedness, and any swaps we enter into may not fully mitigate our interest rate risk. With the senior secured term loan fully drawn, it is estimated that a one percentage point change in market interest rates above 1.75% would result in a change in our annual interest expense of approximately $7 million. If the senior secured revolving credit facility was fully drawn, it is estimated that a one percentage point change in market interest rates would result in a change in our annual interest expense of approximately $8 million.

The GenOn Marsh Landing credit agreement is also subject to variable interest rates. The credit facility consists of a $155 million tranche A senior secured term loan facility, a $345 million tranche B senior secured term loan facility, a $50 million senior secured letter of credit facility to support GenOn Marsh Landing s debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing s collateral requirements under its PPA with PG&E. Interest on the tranche A term loans will be based on a base rate or a LIBOR rate plus an initial applicable margin of 1.5% for base rate loans and 2.5% for LIBOR loans (with such margin increasing 0.25% every three years). Interest on the tranche B term loans will be based on a base rate or a LIBOR rate plus an initial applicable margin of 1.75% for base rate loans and 2.75% for LIBOR loans (with such margin increasing 0.25% every three years). GenOn Marsh Landing entered into interest rate swaps to reduce the interest rate risks with respect to the term loan. The effective interest rate that GenOn Marsh Landing will pay for the term loan from the commercial operations date is 5.91% (plus the step-up in margin over time). The interest rate swaps cover 100% of the expected outstanding term loan balances during the operating period and a substantial portion of the expected outstanding term loan balances during the construction period. The remaining borrowings during the construction period are still subject to variability in interest rates. At the projected peak borrowing levels during the construction period, a one percentage point change in market interest rates would result in a change in our annual interest cost of less than $1 million.

Coal Agreement Risk

Our coal supply comes primarily from the Northern Appalachian and Central Appalachian coal regions. We enter into contracts of varying tenors to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase most of our coal from a small number of suppliers under contracts with terms of varying lengths, some of which extend to 2013 and one that extends to 2020. Excluding our Keystone and Conemaugh generating facilities (which are not 100% owned by us) and excluding our

Seward generating facility (which burns waste coal supplied by an all-requirements contract), we had exposure to three counterparties at December 31, 2010 and 2009, that each represented an exposure of more than 10% of our total coal commitments, by volume, for the respective succeeding year, and in aggregate represented approximately 76% and 61% of our total coal commitments at December 31, 2010 and 2009, respectively. At December 31, 2010, one counterparty represented an exposure of 52% of these total coal commitments, by volume.

In addition, we have non-performance risk associated with our coal agreements. There is risk that our coal suppliers may not provide the contractual quantities on the dates specified within the agreements, or the deliveries may be carried over to future periods. If our coal suppliers do not perform in accordance with the agreements, we may have to procure coal in the market to meet our needs, or power in the market to meet our obligations. In addition, generally our coal suppliers do not have investment grade credit ratings nor do they post collateral with us and, accordingly, we may have limited ability to collect damages in the event of default by such suppliers. We seek to mitigate this risk through diversification of coal suppliers, to the extent possible, and through guarantees. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers. Non-performance or default risk by our coal suppliers could have a material adverse effect on our future results of operations, financial condition and cash flows. See note 4(c) to our consolidated financial statements for further explanation of these agreements and our credit concentration tables.

Certain of our coal contracts are not required to be recorded at fair value under the accounting guidance for derivative financial instruments. As such, these contracts are not included in derivative contract assets and liabilities in the consolidated balance sheets. These contracts contain pricing terms that are favorable compared to forward market prices at December 31, 2010, and are projected to provide a $95 million benefit to our realized value of hedges through 2013 as the coal is utilized in the production of electricity.

Item 8. *Financial Statements and Supplementary Data*

The financial statements and schedules are listed in Part IV, Item 15 of this Form 10-K.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

Effectiveness of Disclosure Controls and Procedures

As required by Exchange Act Rule 13a-15(b), our management, including our Chief Executive Officer and our Chief Financial Officer, conducted an assessment of the effectiveness of the design and operation of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of December 31, 2010. Based upon this assessment, our management concluded that, as of December 31, 2010, the design and operation of these disclosure controls and procedures were effective.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined by Rules 13a-15(f) under the Exchange Act). The Company s internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with United States generally accepted accounting principles. Internal control over financial reporting includes those processes and procedures that:

pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

provide reasonable assurance that transactions are recorded properly to allow for the 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;

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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 consolidated financial statements; and

provide reasonable assurance as to the detection of fraud.

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we carried out an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2010. In conducting our assessment, management utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*. Based on this assessment, management concluded that our internal control over financial reporting was effective as of December 31, 2010.

Our independent registered public accounting firm, KPMG LLP, has issued an attestation report on our internal control over financial reporting. KPMG LLP s report can be found on page F-1.

Changes in Internal Control over Financial Reporting

On December 3, 2010, Mirant and RRI Energy completed the Merger to form GenOn. During the 2010 period leading up to the Merger, there were no changes to either company s internal controls over financial reporting that were reasonably likely to have a material effect. For the post merger period, management maintained the effectiveness of each company s legacy controls over financial reporting. In addition, management designed and tested new controls over the financial reporting process which support the preparation of GenOn s financial statements in accordance with GAAP. To support business integration plans, a process for evaluating and addressing necessary changes to the control environment over financial reporting was adopted. These changes in internal control were considered in management s assessment at December 31, 2010.

Item 9B. ***Other Information.***

None.

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PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

Item 11. *Executive Compensation.*

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The following table sets forth the compensation plans under which our equity securities were authorized for issuance at December 31, 2010:

Plant Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (in millions)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities to be Issued Upon Exercise of Outstanding Options,Warrants and Rights) (in millions)
Equity compensation plans approved by security holders	20	$ 9.20	45
Equity compensation plans not approved by security holders			
Total	20	$ 9.19	45

As of the date of the Merger, the GenOn Energy, Inc. 2010 Omnibus Incentive Plan became effective and permits the Company to grant various stock-based compensation awards to employees, consultants and directors. We terminated the GenOn Energy, Inc. 2002 Stock Plan, the GenOn Energy, Inc. 2002 Long-Term Incentive Plan, the Long-Term Incentive Plan of GenOn Energy, Inc., the GenOn Energy, Inc. Transition Stock Plan and the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. Outstanding awards under the terminated plans remain subject to the terms and conditions of the applicable plans.

The GenOn Energy, Inc. 2010 Omnibus Incentive Plan provides for the granting of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards, other stock-based awards, covered employee annual incentive awards and non-employee director awards.

Other information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions and Director Independence.***

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services.***

The information required by this Item will be set forth in our definitive proxy statement for our annual meeting of stockholders, which involves the election of directors and is incorporated herein by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) 1. Financial Statements

2. Financial Statement Schedules

3. Exhibits

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
GenOn Energy, Inc.:

We have audited the accompanying consolidated balance sheets of GenOn Energy, Inc. and subsidiaries (the Company) at December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the years in the three-year period ended December 31, 2010. We also have audited the Company s internal control over financial reporting at 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 consolidated financial statements, 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 within Item 9A. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company s internal control over financial reporting based on our 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 consolidated 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.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GenOn Energy, Inc. and subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting at December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

/s/ KPMG LLP

Houston, Texas
March 1, 2011

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GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	2010	2009	2008
	(in millions, except per share data)		
Operating revenues (including unrealized gains (losses) of $45 million, $(2) million and $840 million, respectively)	$ 2,270	$ 2,309	$ 3,188
Cost of fuel, electricity and other products (including unrealized (gains) losses of $87 million, $(49) million and $54 million, respectively)	963	710	1,059
Gross Margin (excluding depreciation and amortization)	1,307	1,599	2,129
Operating Expenses:			
Operations and maintenance	846	609	667
Depreciation and amortization	224	149	144
Impairment losses	565	221	
Gain on sales of assets, net	(4)	(22)	(39)
Total operating expenses	1,631	957	772
Operating Income (Loss)	(324)	642	1,357
Other Expense (Income), net:			
Gain on bargain purchase	(518)		
Interest expense	254	138	189
Interest income	(1)	(3)	(70)
Equity in income of affiliates		1	16
Other, net	(7)		5
Total other (income) expense, net	(272)	136	140
Income (Loss) From Continuing Operations Before Income Taxes	(52)	506	1,217
Provision (benefit) for income taxes	(2)	12	2
Income (Loss) From Continuing Operations	(50)	494	1,215
Income From Discontinued Operations, net			50
Net Income (Loss)	$ (50)	$ 494	$ 1,265
Basic EPS:			
Basic EPS from continuing operations	$ (0.11)	$ 1.20	$ 2.31
Basic EPS from discontinued operations			0.09
Basic EPS	$ (0.11)	$ 1.20	$ 2.40

Diluted EPS:			
Diluted EPS from continuing operations	$ (0.11)	$ 1.20	$ 2.15
Diluted EPS from discontinued operations			0.09
Diluted EPS	$ (0.11)	$ 1.20	$ 2.24
Weighted average shares outstanding	441	411	527
Effect of dilutive securities		1	38
Weighted average shares outstanding assuming dilution	441	412	565

The accompanying notes are an integral part of these consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,402	$ 1,953
Funds on deposit	1,834	181
Receivables, net	536	412
Derivative contract assets	1,420	1,416
Inventories	554	241
Prepaid expenses	155	144
Total current assets	6,901	4,347
Property, Plant and Equipment, net	6,298	3,633
Noncurrent Assets:		
Intangible assets, net	144	171
Derivative contract assets	716	599
Deferred income taxes	362	376
Prepaid rent	348	304
Other	505	98
Total noncurrent assets	2,075	1,548
Total Assets	$ 15,274	$ 9,528
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 2,058	$ 75
Accounts payable and accrued liabilities	902	718
Derivative contract liabilities	1,227	1,150
Deferred income taxes	362	376
Other	133	4
Total current liabilities	4,682	2,323
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,023	2,556
Derivative contract liabilities	189	163
Pension and postretirement obligations	171	113
Other	579	58

Total noncurrent liabilities	4,962	2,890
Commitments and Contingencies		
Stockholders Equity:		
Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at December 31, 2010 and 2009		
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 770,857,530 shares and 410,924,221 shares at December 31, 2010 and 2009, respectively	1	
Additional paid-in capital	7,432	6,096
Accumulated deficit	(1,778)	(1,728)
Accumulated other comprehensive loss	(25)	(53)
Total stockholders equity	5,630	4,315
Total Liabilities and Stockholders Equity	$ 15,274	$ 9,528

The accompanying notes are an integral part of these consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS)

	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
			(in millions)		
Balance, December 31, 2007	$	$ 8,774	$ (3,486)	$ 22	$ 5,310
Share repurchases		(2,744)			(2,744)
Stock-based compensation expense		26			26
Exercises of stock options and warrants		18			18
Adoption of accounting guidance related to fair value measurement			1		1
Adoption of accounting guidance related to pension and other postretirement benefits measurement date transition			(2)	(1)	(3)
Total stockholders equity before other comprehensive income					2,608
Net income			1,265		1,265
Pension and other postretirement benefits, net of tax of $0				(111)	(111)
Total other comprehensive income					1,154
Balance, December 31, 2008		6,074	(2,222)	(90)	3,762
Share repurchases		(4)			(4)
Stock-based compensation expense		26			26
Total stockholders equity before other comprehensive income					3,784
Net income			494		494
Pension and other postretirement benefits, net of tax of $0				37	37
Total other comprehensive income					531
Balance, December 31, 2009		6,096	(1,728)	(53)	4,315
Share repurchases		(11)			(11)
Stock-based compensation expense		42			42
Exercise of stock options		1			1
Shares issued pursuant to the Merger of Mirant and RRI Energy	1	1,304			1,305

Total stockholders equity before other comprehensive income					5,652
Net loss			(50)		(50)
Pension and other postretirement benefits, net of tax of $0				6	6
Change in fair value of qualifying derivatives, net of settlements, net of tax of $0				21	21
Change in fair value of available-for-sale securities, net of tax of $0				1	1
Total other comprehensive loss					(22)
Balance, December 31, 2010	$ 1	$ 7,432	$ (1,778)	$ (25)	$ 5,630

The accompanying notes are an integral part of these consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	2010	2009	2008
		(in millions)	
Cash Flows from Operating Activities:			
Net income (loss)	$ (50)	$ 494	$ 1,265
Income from discontinued operations, net			50
Income (loss) from continuing operations	(50)	494	1,215
Adjustments to reconcile income (loss) from continuing operations and changes in other operating assets and liabilities to net cash provided by operating activities:			
Depreciation and amortization	229	156	148
Impairment losses	565	221	
Gain on sales of assets, net	(4)	(22)	(39)
Net changes in derivative contracts	42	(47)	(786)
Stock-based compensation expense	41	24	25
Postretirement benefits curtailment gain	(37)		(5)
Lower of cost or market inventory adjustments	22	32	65
Equity in income of affiliates		1	16
Gain on bargain purchase	(518)		
Potomac River settlement obligation	32		
Other, net	28		4
Changes in operating assets and liabilities, net of effects of the Merger:			
Receivables, net	(10)	348	(209)
Funds on deposit	(42)	21	104
Inventories	(65)	(35)	47
Other assets	(41)	(47)	(29)
Accounts payable and accrued liabilities	(3)	(334)	204
Other liabilities	10	1	(63)
Total adjustments	249	319	(518)
Net cash provided by operating activities of continuing operations	199	813	697
Net cash provided by operating activities of discontinued operations	6	9	50
Net cash provided by operating activities	205	822	747
Cash Flows from Investing Activities:			
Cash acquired from RRI Energy, Inc.	717		
Capital expenditures	(304)	(676)	(731)
Proceeds from the sales of assets	4	26	42
Capital contributions		(5)	(20)
Restricted deposits payments	(1,586)		(34)

Restricted deposits withdrawals	41	1	
Other, net	(43)	3	4
Net cash used in investing activities of continuing operations	(1,171)	(651)	(739)
Net cash provided by investing activities of discontinued operations			25
Net cash used in investing activities	(1,171)	(651)	(714)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	1,896		
Payments of long-term debt	(379)	(45)	(420)
Debt issuance costs	(92)		
Share repurchases	(11)	(4)	(2,761)
Proceeds from exercises of stock options and warrants	1		18
Net cash provided by (used in) financing activities	1,415	(49)	(3,163)
Net Increase (Decrease) in Cash and Cash Equivalents	449	122	(3,130)
Cash and Cash Equivalents, beginning of year	1,953	1,831	4,961
Cash and Cash Equivalents, end of year	$ 2,402	$ 1,953	$ 1,831
Supplemental Disclosures:			
Cash paid for interest, net of amounts capitalized	$ 244	$ 124	$ 175
Cash paid for income taxes (net of refunds received)	$ (1)	$ 9	$
Cash paid for claims and professional fees from bankruptcy	$	$ 1	$ 17
Supplemental Disclosures for Non-Cash Investing and Financing Activities:			
Issuance of common stock to effect the Merger	$ 1,305	$	$

The accompanying notes are an integral part of these consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2010, 2009 and 2008

1. Description of Business and Accounting and Reporting Policies

Background

GenOn provides energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States through ownership and operation of, and contracting for, power generation capacity. GenOn is a wholesale generator with approximately 24,200 MW of net electric generating capacity in the PJM, MISO, Northeast and Southeast regions and California. GenOn also operates integrated asset management and energy marketing organizations, including proprietary trading operations.

GenOn, a Delaware corporation, was formed in August 2000 by CenterPoint (then known as Reliant Energy, Incorporated) in connection with the planned separation of its regulated and unregulated operations. CenterPoint transferred substantially all of its unregulated businesses, including the name Reliant Energy, to the company now named GenOn Energy, Inc. In May 2001, Reliant Energy (then known as Reliant Resources, Inc.) became a publicly traded company and in September 2002, CenterPoint distributed its remaining ownership of Reliant Energy s common stock to its stockholders. RRI Energy changed its name from Reliant Energy, Inc. effective May 2, 2009 in connection with the sale of its retail business. GenOn changed its name from RRI Energy, Inc. effective December 3, 2010. The Company refers to GenOn Energy, Inc. and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Merger.

Merger of Mirant and RRI Energy

On December 3, 2010, Mirant and RRI Energy completed the Merger contemplated by the Merger Agreement. Upon completion of the Merger, RRI Energy Holdings, Inc. (Merger Sub), a direct and wholly-owned subsidiary of RRI Energy merged with and into Mirant, with Mirant continuing as the surviving corporation and a wholly-owned subsidiary of RRI Energy. Each of Mirant and RRI Energy received legal opinions that the Merger qualified as a tax-free reorganization under the IRC. Accordingly, none of RRI Energy, Merger Sub, Mirant or any of the Mirant stockholders will recognize any gain or loss in the transaction, except that Mirant stockholders will recognize a gain or loss with respect to cash received in lieu of fractional shares of RRI Energy common stock. Upon the closing of the Merger, each issued and outstanding share of Mirant common stock, including grants of restricted common stock, automatically converted into 2.835 shares of common stock of RRI Energy based on the Exchange Ratio. Additionally, upon the closing of the Merger, RRI Energy was renamed GenOn. Mirant stock options and other equity awards converted upon completion of the Merger into stock options and equity awards with respect to GenOn common stock, after giving effect to the Exchange Ratio. At the close of the Merger, former Mirant stockholders owned approximately 54% of the equity of the combined company and former RRI Energy stockholders owned approximately 46% of the equity of the combined company. See note 2 for additional information on the Merger and note 6 for the related debt transactions.

Basis of Presentation

The consolidated financial statements of GenOn and its wholly-owned subsidiaries have been prepared in accordance with GAAP. The consolidated financial statements have been prepared from records maintained by GenOn and its subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Upon completion of the Merger, Mirant stockholders had a majority of the voting interest in the combined company. Although RRI Energy issued shares of RRI Energy common stock to Mirant stockholders to effect the Merger, the Merger is accounted for as a reverse acquisition under the acquisition method of accounting. Under the acquisition method of accounting, Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the consolidated financial

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

statements of GenOn include the results of Mirant, from January 1, 2008 through December 2, 2010, and include the results of the combined entities for the period from December 3, 2010 through December 31, 2010, including operating revenues from RRI Energy of $168 million and net loss of $60 million after the Merger. The consolidated financial statements presented herein for periods ended prior to the closing of the Merger (and any other financial information presented herein with respect to such pre-merger dates, unless otherwise specified) are the consolidated financial statements and other financial information of Mirant.

At December 31, 2010, substantially all of GenOn s subsidiaries are wholly-owned and located in the United States. GenOn does not consolidate five power generating facilities, which are under operating leases (see note 10 for further discussion of the operating leases); a 50% equity investment in a cogeneration generating facility; and a VIE, for which it is not the primary beneficiary (see note 15 for further discussion of MC Asset Recovery). In accordance with the accounting guidance related to discontinued operations, the results of operations of the Company s businesses and facilities that have been disposed of and have met the criteria for such classification, have been reclassified to discontinued operations. Certain prior period amounts have been reclassified to conform to the current year financial statement presentation.

Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make various estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. GenOn s significant estimates include:

- estimating the fair value of assets acquired and liabilities assumed in connection with the Merger;
- determining the fair value of certain derivative contracts;
- estimating future taxable income in evaluating its deferred tax asset valuation allowance;
- estimating the useful lives of long-lived assets;
- determining the value of asset retirement obligations;
- estimating future cash flows in determining impairments of long-lived assets and definite-lived intangible assets;
- estimating the fair value and expected return on plan assets, discount rates and other actuarial assumptions used in estimating pension and other postretirement benefit plan liabilities; and
- estimating losses to be recorded for contingent liabilities.

GenOn evaluates events that occur after its balance sheet date but before its financial statements are issued for potential recognition or disclosure. Based on the evaluation, GenOn determined that there were no material subsequent events for recognition or disclosure other than those disclosed herein.

Revenue Recognition

GenOn recognizes revenue when earned and collection is probable. GenOn earns revenue from the following sources: (a) power generation revenues, (b) contracted and capacity revenues, (c) fuel sales and proprietary trading revenues and (d) power hedging revenues.

Power Generation Revenues. GenOn recognizes revenue from the sale of electricity from its generating facilities. Sales of energy primarily are based on economic dispatch, or as-ordered by an ISO or RTO, based on member participation agreements, but without an underlying contractual commitment. ISO and RTO revenues and revenues from sales of energy based on economic-dispatch are recorded on the basis of MWh

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

delivered, at the relevant day-ahead or real-time prices. Additionally, the Company includes revenue from the sale of steam in power generation revenues.

Contracted and Capacity Revenues. GenOn recognizes revenue received from providing ancillary services and revenue received from an ISO or RTO based on auction results or negotiated contract prices for making installed generation capacity available to meet system reliability requirements. In addition, when a long-term electric power agreement conveys to the buyer of the electric power the right to control the generating capacity of GenOn s facility, that agreement is evaluated to determine if it is a lease of the generating facility rather than a sale of electric power. Operating lease revenue for GenOn s generating facilities is normally recorded as capacity revenue.

Fuel Sales and Proprietary Trading Revenues. GenOn recognizes revenue from the sale of fuel oil and natural gas and revenues associated with fuel oil management and proprietary trading activities.

Power Hedging Revenues. GenOn recognizes revenue from contracts which include both the sale of power and natural gas used to hedge power prices as well as hedges to capture the incremental value related to the geographic location of its physical assets.

The following table reflects GenOn s revenues by type:

	2010	2009	2008
		(in millions)	
Power generation revenues	$ 1,266	$ 805	$ 1,841
Contracted and capacity revenues	607	592	612
Fuel sales and proprietary trading revenues	29	67	90
Power hedging revenues	368	845	645
Total operating revenues	$ 2,270	$ 2,309	$ 3,188

In accordance with accounting guidance related to derivative financial instruments, physical transactions, or revenues from the sale of generated electricity to ISOs and RTOs, are recorded on a gross basis in the consolidated statements of operations. Financial transactions, or the buying and selling of energy for trading purposes, are recorded on a net basis in the consolidated statements of operations.

Cost of Fuel, Electricity and Other Products

Cost of fuel, electricity and other products on GenOn s consolidated statements of operations includes the costs of goods produced and sold through the combustion process, including the costs associated with handling and disposal of ash, natural gas transportation and services rendered during a reporting period. Cost of fuel, electricity and other products also includes purchased emissions allowances for CO_2, SO_2 and NO_x and the settlements of and changes in fair value of derivative financial instruments used to hedge fuel economically. Additionally, cost of fuel, electricity and other products includes lower of cost or market inventory adjustments. Cost of fuel, electricity and other products excludes depreciation and amortization. Gross margin is total operating revenues less cost of fuel, electricity and other products.

Derivatives and Hedging Activities

In connection with the business of generating electricity, GenOn is exposed to energy commodity price risk associated with the acquisition of fuel and emissions allowances needed to generate electricity, the price of electricity produced and sold, and the fair value of fuel inventories. In addition, the open positions in GenOn s trading activities, comprised of proprietary trading and fuel oil management activities, expose it to risks associated with changes in energy commodity prices. GenOn, through its asset management activities, enters into a variety of exchange-traded and OTC energy and energy-related derivative financial instruments,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

such as forward contracts, futures contracts, option contracts and financial swap agreements to manage exposure to commodity price risks. These contracts have varying terms and durations, which range from a few days to years, depending on the instrument. GenOn s proprietary trading activities also utilize similar derivative contracts in markets where GenOn has a physical presence to attempt to generate incremental gross margin. GenOn s fuel oil management activities use derivative financial instruments to hedge economically the fair value of GenOn s physical fuel oil inventories, optimize the approximately three million barrels of storage capacity that GenOn owns or leases, as well as attempt to profit from market opportunities related to timing and/or differences in the pricing of various products.

Derivative financial instruments are recorded in the consolidated balance sheets at fair value, except for derivative contracts that qualify for the normal purchase or normal sale exceptions, which are not in the consolidated balance sheet or results of operations prior to settlement based on accrual accounting treatment. GenOn presents its derivative contract assets and liabilities on a gross basis (regardless of master netting arrangements with the same counterparty). Cash collateral amounts are also presented on a gross basis.

If certain criteria are met, a derivative financial instrument may be designated as a fair value hedge or cash flow hedge. In the fourth quarter of 2010, GenOn Marsh Landing entered into interest rate protection agreements (interest rate swaps) in connection with the project financing, which have been designated as cash flow hedges. GenOn Marsh Landing entered into the interest rate swaps to reduce the risks with respect to the variability of the interest rates for the term loan. See note 6 for further information on the GenOn Marsh Landing project financing and the interest rate swaps. With the exception of these interest rate swaps, the Company did not have any other derivative financial instruments that it had designated as fair value or cash flow hedges for accounting purposes during 2010, 2009 or 2008.

The changes in fair value of cash flow hedges are deferred in accumulated other comprehensive loss, net of tax, to the extent the contracts are, or have been, effective as hedges, until the forecasted transactions affect earnings. At the time the forecasted transactions affect earnings, GenOn reclassifies the amounts in accumulated other comprehensive loss into earnings. GenOn records the ineffective portion of changes in fair value of cash flow hedges immediately into earnings.

Derivative financial instruments designated as cash flow hedges must have a high correlation between price movements in the derivative and the hedged item. If and when an acceptable level of correlation no longer exists, hedge accounting ceases and changes in fair value are recognized in GenOn s results of operations. If it becomes probable that a forecasted transaction will not occur, GenOn immediately recognizes the related deferred gains or losses in its results of operations. Changes in fair value of the associated hedging instrument are then recognized immediately in earnings for the remainder of the contract term unless a new hedging relationship is designated.

For GenOn s derivative financial instruments that have not been designated as cash flow hedges for accounting purposes, changes in such instruments fair values are recognized currently in earnings. GenOn s derivative financial instruments are categorized based on the business objective the instrument is expected to achieve: asset management or trading, which includes proprietary trading and fuel oil management. For asset management activities, changes in fair value and settlement of derivative financial instruments used to hedge electricity economically are reflected in operating revenue and changes in fair value and settlement of derivative financial instruments used to hedge fuel economically are reflected in cost of fuel, electricity and other products in the consolidated statements of operations. Changes in the fair value and settlements of derivative financial instruments for proprietary trading and fuel oil management activities are recorded on a net basis as operating revenue in the consolidated statements of operations.

In May 2010, GenOn concluded that it could no longer assert that physical delivery is probable for many of its coal agreements. The conclusion was based on expected generation levels, changes observed in the coal markets and the completion of GenOn s coal blending facility at its Morgantown generating facility that allows for greater flexibility of GenOn s coal supply. Because GenOn can no longer assert that physical delivery of coal from these agreements is probable, they do not qualify for the normal purchase exception and GenOn is required to apply fair value accounting for these contracts in the current period and prospectively.

GenOn also considers risks associated with interest rates, counterparty credit and its own non-performance risk when valuing its derivative financial instruments. The nominal value of the derivative contract assets and liabilities is discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of GenOn s transactions being valued. See note 4 for discussion on fair value measurements and note 4 for further discussion of GenOn s credit policies.

Concentration of Revenues

During 2010, GenOn had $1.5 billion in revenues from PJM, which represented 64% of consolidated revenues. The revenues generated from this counterparty are included in the Eastern PJM, Western PJM/MISO and Energy Marketing segments. During 2009, GenOn had $1.0 billion in revenues from PJM, which represented 43% of consolidated revenues. The revenues generated from this counterparty are primarily included in the Eastern PJM segment. Additionally, during 2009 GenOn had $332 million in revenues from another counterparty, which represented 14% of consolidated revenues. The revenues generated from this counterparty are included in the Eastern PJM, Energy Marketing and Other Operations segments. During 2008, GenOn had $1.5 billion in revenues from PJM, which represented 48% of consolidated revenues. The revenues generated from this counterparty are primarily included in the Eastern PJM segment. Additionally, during 2008 GenOn had $470 million in revenues from another counterparty, which represented 15% of consolidated revenues. The revenues generated from this counterparty are primarily included in the Other Operations segment.

Coal Supplier Concentration Risk

GenOn s coal supply comes primarily from the Northern Appalachian and Central Appalachian coal regions. GenOn enters into contracts of varying tenors to secure appropriate quantities of fuel that meet the varying specifications of its generating facilities. For the coal-fired generating facilities, GenOn purchases most of its coal from a small number of suppliers under contracts with terms of varying lengths, some of which extend to 2013 and one that extends to 2020. Excluding the Keystone and Conemaugh generating facilities (which are not 100% owned by GenOn) and excluding the Seward generating facility (which burns waste coal supplied by an all-requirements contract), GenOn had exposure to three counterparties at December 31, 2010 and 2009, that each represented an exposure of more than 10% of its total coal commitments, by volume, for the respective succeeding year, and in aggregate represented approximately 76% and 61% of the Company s total coal commitments at December 31, 2010 and 2009, respectively. At December 31, 2010, one counterparty represented an exposure of 52% of these total coal commitments, by volume.

Concentration of Labor Subject to Collective Bargaining Agreements

At December 31, 2010, approximately 47% of GenOn s employees are subject to collective bargaining agreements. Of those employees subject to collective bargaining agreements, 32% are represented by IBEW Local 459 in the Western PJM/MISO segment and 29% are represented by IBEW Local 1900 in the Eastern PJM segment. Less than five percent of GenOn s employees are subject to collective bargaining agreements that will expire in 2011. GenOn intends to negotiate the renewal of these agreements and does not anticipate any disruptions to GenOn s operations.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents

GenOn considers all short-term investments with an original maturity of three months or less to be cash equivalents. At December 31, 2010, except for amounts held in bank accounts to cover current payables, all of GenOn s cash and cash equivalents were invested in AAA-rated United States Treasury money market funds.

Restricted Cash

Restricted cash is included in current and noncurrent assets as funds on deposit and other noncurrent assets, respectively, in the consolidated balance sheets. Restricted cash includes the following:

	December 31, 2010	2009
	(in millions)	
Funds deposited with the trustee to discharge the GenOn senior secured notes, due 2014[1]	$ 285	$
Funds deposited with the trustee to discharge the GenOn North America senior notes, due 2013[1]	866	
Funds deposited with the trustee to defease the PEDFA fixed-rate bonds, due 2036[1]	394	
Cash collateral posted[2]	299	84
GenOn North America deposits[3]		124
GenOn Marsh Landing development project cash collateral posted[4]	106	12
Other	38	
Total current and noncurrent funds on deposit	1,988	220
Less: Current funds on deposit	1,834	181
Total noncurrent funds on deposit	$ 154	$ 39

(1) See note 6.

(2) Represents cash collateral posted for energy trading and marketing and other operating activities; includes $32 million related to the Potomac River Settlement, see notes 5(c) and 19; includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations.

(3) Represents deposits posted under GenOn North America senior secured term loans to support the issuance of letters of credit. These amounts were returned in 2010 as a result of the repayment of the GenOn North America senior secured term loans.

(4) Represents cash-collateralized letters of credit to support the GenOn Marsh Landing development project.

Inventories

Inventories consist primarily of materials and supplies, fuel oil, coal and purchased emissions allowances. Inventory is generally stated at the lower of cost or market value and is expensed on a weighted average cost basis. Fuel inventory is removed from the inventory account as it is used in the generation of electricity or sold to third parties, including sales related to GenOn s fuel oil management, natural gas transportation and storage activities. Materials and supplies are removed from the inventory account when they are used for repairs, maintenance or capital projects. Purchased emissions allowances are removed from inventory and charged to cost of fuel, electricity and other products in the consolidated statements of operations as they are utilized for emissions volumes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Inventories were comprised of the following:

	December 31, 2010	December 31, 2009
	(in millions)	
Fuel inventory:		
Fuel oil	$ 170	$ 99
Coal	153	52
Natural gas	1	
Other	1	1
Materials and supplies	194	66
Purchased emissions allowances	35	23
Total inventories	$ 554	$ 241

During 2010, 2009 and 2008, GenOn recorded $22 million, $32 million and $65 million, respectively, for lower of average cost or market valuation adjustments in cost of fuel, electricity and other products.

Granted Emissions Allowances

Included in property, plant and equipment are: (a) emissions allowances granted by the EPA that were projected to be required to offset physical emissions and (b) emissions allowances granted by the EPA that were projected to be in excess of those required to offset physical emissions related to generating facilities owned by the Company. These emissions allowances were recorded at fair value at the date of the acquisition of the facility and are depreciated on a straight-line basis over the estimated useful life of the respective generating facility and are charged to depreciation and amortization expense in the consolidated statements of operations.

Included in other intangible assets are emissions allowances related to the Dickerson and Morgantown baseload units leased by the Company. Emissions allowances related to leased units are recorded at fair value at the commencement of the lease. These emissions allowances are amortized on a straight-line basis over the term of the lease for leased units, and are charged to depreciation and amortization expense in the consolidated statements of operations.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost, which includes materials, labor, associated payroll-related and overhead costs and the cost of financing construction. The cost of routine maintenance and repairs, such as inspections and corrosion removal, and the replacement of minor items of property are charged to expense as incurred. Certain expenditures incurred during a major maintenance outage of a generating facility are capitalized, including the replacement of major component parts and labor and overhead incurred to install the parts. Depreciation of the recorded cost of depreciable property, plant and equipment is determined using primarily composite rates. Leasehold improvements are depreciated over the shorter of the expected life of the related equipment or the lease term. Upon the retirement or sale of property, plant and equipment, the cost of such assets and the related accumulated depreciation are removed from the consolidated balance sheets. No gain or loss is recognized for ordinary retirements in the normal course of business since the composite depreciation rates used by GenOn take into account the effect of interim retirements.

Impairment of Long-Lived Assets

GenOn evaluates long-lived assets, such as property, plant and equipment and purchased intangible assets subject to amortization, for impairment whenever events or changes in circumstances indicate that the carrying

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

amount of the asset may not be recoverable. Such evaluations are performed in accordance with the accounting guidance related to evaluating long-lived assets for impairment. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to the estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future cash flows, an impairment charge is recognized as the amount by which the carrying amount of the asset exceeds its fair value. See note 5(c) for further discussion of assets reviewed for impairment.

Capitalization of Interest Cost

GenOn capitalizes interest on projects during their construction period. The Company determines which debt instruments represent a reasonable measure of the cost of financing construction in terms of interest costs incurred that otherwise could have been avoided. These debt instruments and associated interest costs are included in the calculation of the weighted average interest rate used for determining the capitalization rate. Once a project is placed in service, capitalized interest, as a component of the total cost of the construction, is depreciated over the estimated useful life of the asset constructed.

During 2010, 2009 and 2008, the Company incurred the following interest costs:

	2010	2009	2008
		(in millions)	
Total interest costs	$ 260	$ 210	$ 237
Capitalized and included in property, plant and equipment, net	(6)	(72)	(48)
Interest expense	$ 254	$ 138	$ 189

The amounts of capitalized interest above include interest accrued. During 2010, 2009 and 2008, cash paid for interest was $250 million, $192 million and $223 million, respectively, of which $6 million, $68 million and $48 million, respectively, were capitalized.

Environmental Costs

GenOn expenses environmental expenditures related to existing conditions that do not have future economic benefit. GenOn capitalizes environmental expenditures for which there is a future economic benefit. GenOn records liabilities for expected future costs, on an undiscounted basis, related to environmental assessments and/or remediation when they are probable and can be reasonably estimated.

Development Costs

GenOn capitalizes project development costs for generating facilities once it is probable that the project will be completed. These costs include professional fees, permits and other third party costs directly associated with the development of a new project. The capitalized costs are depreciated over the life of the asset or charged to operating expense if the completion of the project is no longer probable. Project development costs are expensed when incurred until the probable threshold is met. The Company began capitalizing project development costs related to the Marsh Landing generating facility upon signing the PPA with PG&E on September 2, 2009. At December 31, 2010, the Company has capitalized $5 million of project development costs related to the Marsh Landing generating facility.

Operating Leases

GenOn leases various assets under non-cancelable leasing arrangements, including generating facilities, office space and other equipment. The rent expense associated with leases that qualify as operating leases is recognized on a straight-line basis over the lease term within operations and maintenance expense in the consolidated statements of operations. The Company s most significant operating leases are GenOn Mid-

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Atlantic s leases of the Dickerson and Morgantown baseload units and REMA s leases of a 16.45% interest in the Conemaugh facility, a 16.67% interest in the Keystone facility and a 100% interest in the Shawville facility. See note 10 for further discussion on these leases.

Intangible Assets

Intangible assets relate primarily to trading rights, development rights, acquired contracts and emissions allowances. Intangible assets with definite useful lives are amortized on a straight-line basis to their estimated residual values over their respective useful lives ranging up to 40 years.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense under the effective interest method over the term of the related debt. The unamortized balance of debt issuance costs is included in other noncurrent assets on the consolidated balance sheets. Changes in debt issuance costs are as follows:

	2010	2009	2008
		(in millions)	
Balance, January 1	$ 29	$ 38	$ 49
Capitalized[1]	92		
Amortized	(9)	(9)	(10)
Accelerated amortization/write-offs[1][2]	(9)		(1)
Balance, December 31	$ 103	$ 29	$ 38

(1) See note 6.

(2) Amounts are considered a portion of the net carrying value of the related debt and are expensed when accelerated as a component of debt extinguishments.

Income Taxes and Deferred Tax Asset Valuation Allowance

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

The guidance related to accounting for income taxes requires that a valuation allowance be established when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income of the appropriate character during the periods in which those temporary differences are deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including the Company s past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. The Company thinks that future sources of taxable income, reversing taxable temporary differences and implemented tax planning strategies will be sufficient to realize deferred tax assets for which no valuation allowance has been established. Additionally, the Company s valuation allowance includes $17 million relating to the tax effects of other comprehensive income items primarily related to employee benefits. These other comprehensive income items will be reduced in the event that the valuation allowance is no longer required.

Earnings per Share

Basic earnings per share is calculated by dividing net income/loss applicable to common stockholders by the weighted average number of common shares outstanding. Diluted earnings per share is computed using the weighted average number of shares of common stock and dilutive potential common shares, including common shares from warrants, restricted stock shares, restricted stock units and stock options using the treasury stock method. Share amounts used in calculating earnings per share reflect Mirant s historical activity to December 2, 2010 retroactively adjusted to give effect to the Exchange Ratio and includes the combined entities for the period from December 3, 2010 through December 31, 2010.

Fair Value of Financial Instruments

The accounting guidance related to the disclosure about fair value of financial instruments requires the disclosure of the fair value of all financial instruments that are not otherwise recorded at fair value in the financial statements. At December 31, 2010 and 2009, financial instruments recorded at contractual amounts that approximate fair value include certain funds on deposit, accounts receivable, notes and other receivables, and accounts payable and accrued liabilities. The fair values of such items are not materially sensitive to shifts in market interest rates because of the short term to maturity of these instruments. The fair value of the Company s long-term debt is estimated using quoted market prices when available. See note 4 for further discussion.

Recently Adopted Accounting Guidance

In December 2007, the FASB issued revised guidance related to accounting for business combinations. This guidance requires an acquirer of a business to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. The guidance also requires disclosure of information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, the guidance requires that acquisition-related costs be expensed as incurred. The provisions of this guidance became effective for acquisitions completed on or after January 1, 2009; however, the income tax considerations included in the guidance were effective as of that date for all acquisitions, regardless of the acquisition date. GenOn adopted this accounting guidance on January 1, 2009, and the adoption had no effect on GenOn s consolidated statements of operations, financial position or cash flows.

On February 12, 2008, the FASB issued guidance related to fair value measurements, which deferred the effective date of fair value measurements for one year for certain nonfinancial assets and liabilities, with the exception of those nonfinancial assets and liabilities that are recognized or disclosed on a recurring basis (at least annually). GenOn s non-recurring nonfinancial assets and liabilities that could be measured at fair value in GenOn s consolidated financial statements include long-lived asset impairments and the initial recognition of asset retirement obligations. GenOn adopted the guidance related to fair value measurements for non-recurring nonfinancial assets and liabilities on January 1, 2009, and the adoption had no effect on GenOn s consolidated statements of operations, financial position or cash flows. GenOn incorporated the recognition and disclosure provisions related to fair value measurements for non-recurring nonfinancial assets and liabilities when applicable. See note 5 for these disclosures.

On March 19, 2008, the FASB issued guidance that enhances the required disclosures for derivative instruments. GenOn utilizes derivative financial instruments to manage its exposure to commodity price risks and for its proprietary trading and fuel oil management activities. GenOn adopted this guidance on January 1, 2009. See note 4 for these disclosures.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 30, 2008, the FASB issued guidance which requires enhanced disclosures about plan assets of an employer s defined benefit pension or other postretirement plan. The enhanced disclosures require additional information on how the fair value of plan assets is measured, including a reconciliation of beginning and ending balances for Level 3 inputs and the valuation techniques used to measure fair value. GenOn adopted the accounting guidance for its defined benefit and other postretirement plan disclosures for 2009. See note 8 for these disclosures.

On April 9, 2009, the FASB issued guidance that requires disclosures about the fair value of financial instruments that are not otherwise recorded at fair value in the interim financial statements. GenOn adopted this accounting guidance for its disclosures of the fair value of financial instruments for the quarter ended June 30, 2009, and the adoption had no effect on GenOn s consolidated statements of operations, financial position or cash flows. See Fair Values of Other Financial Instruments in note 4 for these disclosures.

On April 9, 2009, the FASB issued guidance which provides additional direction on determining whether a market for a financial asset is not active and a transaction is not distressed for fair value measurements. Under distressed market conditions, GenOn needs to weigh all available evidence in determining whether a transaction occurred in an orderly market. This guidance requires additional judgment by GenOn when determining the fair value of derivative contracts in the current economic environment. GenOn adopted this accounting guidance for its fair value measurements for the quarter ended June 30, 2009, and the adoption did not have a material effect on GenOn s consolidated statements of operations, financial position or cash flows.

On July 1, 2009, the FASB issued guidance which codified all authoritative nongovernmental GAAP into a single source. The codified guidance supersedes all existing accounting standards, but does not change the contents of those standards. GenOn adopted this accounting guidance for the quarter ended September 30, 2009, and GenOn changed its references to accounting literature to conform to the codified source of authoritative nongovernmental GAAP.

On August 27, 2009, the FASB issued updated guidance for measuring the fair value of liabilities. The guidance clarifies that a quoted price for the identical liability in an active market is the best evidence of fair value for that liability, and in the absence of a quoted market price, the liability may be measured at fair value at the amount that GenOn would receive as proceeds if it were to issue that liability at the measurement date. GenOn adopted this accounting guidance for its fair value measurements of liabilities for the quarter ended September 30, 2009, and the adoption did not have a material effect on GenOn s consolidated statements of operations, financial position or cash flows.

On September 30, 2009, the FASB issued guidance for reporting entities that have investments in certain entities that calculate net asset value per share or an equivalent. This guidance provides a practical expedient to measure the fair value using net asset value per share for investments that fall within the scope of the guidance. GenOn s pension plans have investments in certain funds that utilize net asset value per share and it has elected this practical expedient to measure the fair value of certain of these funds. GenOn adopted the accounting guidance for its defined benefit and other postretirement plan disclosures for 2009. See note 8 for these disclosures.

On June 12, 2009, the FASB issued guidance which requires GenOn to perform an analysis to determine whether its variable interest gives it a controlling financial interest in a VIE. This analysis should identify the primary beneficiary of a VIE. This guidance also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a VIE and enhances the disclosures to provide more information regarding GenOn s involvement in a VIE. GenOn adopted this accounting guidance on January 1, 2010, and as a result, deconsolidated MC Asset Recovery. See note 15 for further details on MC Asset Recovery.

On January 21, 2010, the FASB issued guidance that enhances the disclosures for fair value measurements. The guidance requires GenOn to disclose separately the amount of significant transfers between Level 1 and Level 2 of the fair value hierarchy, the reasons for the significant transfers, the valuation techniques and

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

inputs used and the classes of assets and liabilities accounted for at fair value on a recurring basis. GenOn adopted this accounting guidance for the quarter ended March 31, 2010. See note 4 for additional information on fair value measurements.

On February 25, 2010, the FASB issued guidance that amends its requirement for public companies to disclose the date through which GenOn has evaluated subsequent events and whether that date represents the date the financial statements were issued or were available to be issued. GenOn adopted the subsequent event disclosure requirements for the quarter ended March 31, 2010, and the adoption had no effect on GenOn s consolidated statements of operations, financial position or cash flows. GenOn continues to evaluate subsequent events through the date when the financial statements are issued.

New Accounting Guidance Not Yet Adopted at December 31, 2010

On January 21, 2010, the FASB issued guidance that requires a reconciliation for Level 3 fair value measurements, including presenting separately the amounts of purchases, issuances and settlements on a gross basis. GenOn currently discloses the amounts of purchases, issuances and settlements on a net basis within its roll forward of Level 3 fair value measurements in note 4. GenOn will present these disclosures in its Form 10-Q for the quarter ended March 31, 2011.

2. Merger

On December 3, 2010, Mirant and RRI Energy completed the Merger. Management thinks the Merger will create significant costs synergies; create a combined company with scale and scope in energy generation and delivery; and create a generation fleet with diversity and strategically positioned with a significant presence across key regions, including the Eastern PJM, Western PJM/MISO, Northeast and Southeast regions and California. In addition, management thinks the Merger will strengthen its balance sheet, provide ample liquidity and increased financial flexibility.

Upon closing, each issued and outstanding share of Mirant common stock automatically converted into 2.835 shares of common stock of RRI Energy, with cash paid in lieu of fractional shares. Approximately 417 million shares of RRI Energy common stock were issued.

In the Merger, all the outstanding Mirant warrants converted into warrants of GenOn entitling the holders to 2.835 shares of GenOn common stock for each warrant. The warrants expired on January 3, 2011. For further details regarding the warrants, see note 13. In addition, see note 9 for details regarding the effect of the Merger on Mirant s and RRI Energy s stock-based incentive awards.

Because the Merger is accounted for as a reverse acquisition with Mirant as the accounting acquirer (see note 1, Basis of Presentation section), the purchase price was computed based on shares of Mirant common stock that would have been issued to RRI Energy s stockholders on the date of the Merger to give RRI Energy an equivalent ownership interest in Mirant as it had in the combined company (approximately 46%). The purchase price was calculated as follows (in millions, except closing stock price):

Number of shares of Mirant common stock that would have been issued to RRI Energy stockholders	125

Closing price of Mirant common stock on December 3, 2010	$ 10.39
Total	1,302
RRI Energy stock options	3
Total purchase price	$ 1,305

The Merger is accounted for under the acquisition method of accounting for business combinations. Accordingly, the Company has conducted an assessment of the net assets acquired and has recognized provisional amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition are expensed as incurred. The initial accounting for the business combination is not complete because the valuations necessary to assess the fair values of certain net assets acquired and contingent liabilities assumed are still in process as a result of the short time period between the closing of the Merger and the end of 2010. The significant assets and liabilities for which provisional amounts are recognized at December 31, 2010 are property, plant and equipment, intangible assets and other long-term liabilities related to out-of-market contracts, contingencies and asset retirement obligations. The provisional amounts recognized are subject to revision until the valuations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments will affect the gain on bargain purchase and material changes could require the financial statements to be retroactively amended. The allocation of the purchase price may be modified up to one year from the date of the Merger, as more information is obtained about the fair value of assets acquired and liabilities assumed. GenOn expects to finalize these amounts during 2011. The provisional allocation of the purchase price is as follows (in millions):

Cash and cash equivalents	$ 717
Current derivative contract assets	156
Inventories	276
Other current assets	303
Property, plant and equipment	3,139(1)
Intangible assets	51
Other noncurrent assets	271
Current derivative contract liabilities	(100)
Other current liabilities	(455)
Long-term debt	(1,931)
Pension and postemployment obligations	(105)
Other noncurrent liabilities	(499)
Estimated fair value of net assets acquired	1,823
Purchase price	1,305
Gain on bargain purchase	$ 518(2)

(1) The valuations of the acquired long-lived assets were primarily based on the income approach, and in particular, discounted cash flow analyses. The income approach was employed for the generating facilities because of the differing age, geographic location, market conditions, asset lives, equipment condition and status of environmental controls of the assets. The discounted cash flows incorporated information based on observable market prices to the extent available and long-term prices derived from proprietary fundamental market modeling. For the generating facilities that were not valued using the income approach, the cost approach was used. The market approach was considered, but was ultimately given no weighting because of many of the factors listed as the primary reasons for application of the income approach as well as a lack of proximity of the observed transactions to the valuation date.

(2) The gain on bargain purchase was recorded in other income in the consolidated statement of operations during 2010. The acquisition is treated as a nontaxable merger for federal income tax purposes and there is no tax deductible goodwill resulting from the Merger.

Because the fair value of the net assets acquired exceeds the purchase price, the Merger is being accounted for as a bargain purchase in accordance with acquisition accounting guidance. The estimated gain

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

on the bargain purchase is primarily a result of differences between the long-term fundamental value of the generating facilities and the effect of the near-term view of the equity markets on the price of Mirant common stock at the close of the Merger, specifically as a result of the following:

- current dark spreads (the difference between the price received for electricity generated compared to the market price of the coal required to produce the electricity) have decreased significantly in recent years as a result of natural gas prices that are lower compared to historical levels and increased coal prices that are affected by international demand;
- uncertainty related to the nature and timing of environmental regulation, including carbon legislation; and
- certain generating facilities owned by RRI Energy prior to the Merger being located in markets experiencing lower demand for electricity as a result of economic conditions but forecasted to have long-term declining reserve margins.

GenOn is subject to material contingencies, some of which may involve substantial amounts, relating to (a) pending natural gas litigation, (b) environmental matters, (c) excess mitigation credits, (d) CenterPoint indemnity, (e) Texas franchise tax audit, (f) sales tax contingencies, (g) refund contingency related to transportation rates and (h) income tax contingencies. For information regarding these contingencies, see notes 7 and 18. As a result of the number of variables and assumptions involved in assessing the possible outcome of these matters, sufficient information does not exist to reasonably estimate the fair value or a range of outcomes for these contingent liabilities, except as disclosed in notes 7 and 18. Unless otherwise noted in notes 7 and 18, GenOn cannot predict the outcome of the matters. These material contingencies have been evaluated in accordance with the accounting guidance for contingencies, and no provisional amounts for these matters have been recorded at the date of the Merger because the recognition criteria have not been met, except as denoted in notes 7 and 18. See note 10 for information regarding guarantees and indemnifications.

In connection with the Merger, GenOn incurred stock issuance costs of an insignificant amount, which were recorded as an increase in additional paid-in capital in stockholders equity as of the date of the Merger and incurred debt issuance costs of $68 million, which are included in other noncurrent assets in the consolidated balance sheet. For information regarding debt issuance costs, see note 1. For information regarding merger-related costs, see note 3.

The unaudited pro forma results give effect to the Merger as if it had occurred on January 1, 2010 and 2009, as applicable. The unaudited pro forma financial information is not necessarily indicative of either future results of operations or results that might have been achieved had the acquisition been consummated as of January 1, 2010 or January 1, 2009, as applicable. The unaudited pro forma results for 2010 and 2009 are as follows:

	2010	2009
	(in millions, except per share data)	
Revenues	$ 4,166	$ 4,115
Income (loss) from continuing operations	(752)	69
Net income (loss)	(746)	951

Earnings (loss) per share from continuing operations:		
Basic and Diluted EPS	$ (0.97)	$ 0.09
Net income (loss) per share:		
Basic and Diluted EPS	$ (0.97)	$ 1.24

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The unaudited pro forma information primarily includes the following adjustments, among others:

- amortization of fair value adjustments related to energy-related contracts;
- additional fuel expense related to fair value adjustments of fuel inventories;
- effects of fair value adjustments of property, plant and equipment; effects of fair value adjustments of debt and the issuance of a new revolving credit facility, new senior secured term loan and new senior unsecured notes; and
- adjustments to income taxes for a zero percent rate applied to the pro forma adjustments and historical federal and state deferred tax expense (benefit).

The unaudited pro-forma results exclude:

- transaction costs of $86 million (including amounts incurred prior to the close of the Merger) because these costs reflect non-recurring charges directly related to the Merger;
- $35 million of severance related to the Merger (see note 3) and $18 million of other merger-related costs;
- write-off of $9 million of unamortized debt issuance costs for the debt refinanced, cash premiums and other transaction costs of the debt refinanced;
- $24 million of expense related to the accelerated vesting of stock-based compensation of former Mirant employees upon the completion of the Merger;
- the gain on bargain purchase; and
- cost savings from operating efficiencies or synergies that could result from the Merger.

3. Merger-related Costs

During 2010, GenOn recognized $114 million of merger-related costs which are recorded in operations and maintenance expense in the consolidated statement of operations and are included in the Other Operations segment. The merger-related costs include (a) $67 million of advisory and legal fees, (b) $35 million of charges associated with employees severed or to be severed and (c) $12 million of costs incurred in connection with integration and other activities. At December 31, 2010, $30 million was included in accounts payable and accrued liabilities in the consolidated balance sheet and will be paid in 2011. In addition, GenOn incurred $24 million related to the accelerated vesting of Mirant s stock-based compensation as a result of the Merger.

4. Financial Instruments

(a) Derivatives and Hedging Activities.

The Company uses derivative financial instruments to manage operational or market constraints, to increase the return on its generation assets and to generate incremental gross margin.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the fair value of the Company s derivative financial instruments:

	Derivative Contract Assets		Derivative Contract Liabilities		Net Derivative Contract Assets (Liabilities)
	Current	Long-Term	Current	Long-Term	
			(in millions)		
December 31, 2010					
Commodity Contracts:					
Asset management	$ 564	$ 627	$ (368)	$ (117)	$ 706
Trading activities	856	70	(859)	(72)	(5)
Total commodity contracts	1,420	697	(1,227)	(189)	701
Interest Rate Contracts		19			19
Total derivatives	$ 1,420	$ 716	$ (1,227)	$ (189)	$ 720
December 31, 2009					
Commodity Contracts:					
Asset management	$ 669	$ 535	$ (404)	$ (99)	$ 701
Trading activities	747	64	(746)	(64)	1
Total derivatives	$ 1,416	$ 599	$ (1,150)	$ (163)	$ 702

The following table presents the net gains (losses) for derivative financial instruments recognized in income in the consolidated statements of operations:

	2010		2009	
Derivatives Not Designated as Hedging Instrument	**Revenues**	**Cost of Fuel, Electricity and Other Products**	**Revenues**	**Cost of Fuel, Electricity and Other Products**
		(in millions)		
Asset Management Commodity Contracts:				
Unrealized	$ 50	$ (87)	$ 111	$ 49
Realized[(1)]	318	(191)	745	(74)

Total asset management	$	368	$	(278)	$	856	$	(25)
Trading Commodity Contracts:								
Unrealized	$	(5)	$		$	(113)	$	
Realized[1]		(23)				145		
Total trading	$	(28)	$		$	32	$	
Total derivatives	$	340	$	(278)	$	888	$	(25)

(1) Represents the total cash settlements of derivative financial instruments during each quarterly reporting period that existed at the beginning of each respective period.

The following table presents the effect of the interest rate swaps designated as cash flow hedges in the consolidated statements of stockholders equity and comprehensive income/loss during 2010 (amount of gain (loss)):

Recognized in OCI on Interest Rate Derivatives	**Location of Gain (Loss) Recognized in Income/Loss**	**Reclassified from Accumulated OCI into Earnings**	**Recognized in Earnings on Derivative[1][2]**
	(in millions)		
$ 21	Interest expense	$	$

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(1) Represents the ineffective portion of the Company s interest rate swaps classified as cash flow hedges. The assessment of effectiveness excludes the default risk of the counterparties to these transactions and the Company s own non-performance risk. The effect of these valuation adjustments was a loss of $2 million during 2010 and was recorded in interest expense.

(2) All of the forecasted transactions (future interest payments) were deemed probable of occurring; therefore, no cash flow hedges were discontinued and no amount was recognized in the Company s results of operations as a result of discontinued cash flow hedges.

At December 31, 2010, the maximum length of time the Company is hedging its exposure to the variability in future cash flows that may result from changes in interest rates is 13 years. Because a significant portion of the interest expense incurred by GenOn Marsh Landing during construction will be capitalized, a majority of the amounts included in accumulated other comprehensive loss will be reclassified to property, plant and equipment and depreciated over the expected useful life of the Marsh Landing generating facility once it commences commercial operations in mid-2013. However, the actual amount reclassified into earnings could vary from the amounts recorded as a result of future changes in interest rates.

The following tables present the notional quantity on long (short) positions for derivative financial instruments:

	Notional Volumes at December 31, 2010		
Derivative Instrument	**Derivative Contract Assets**	**Derivative Contract Liabilities (in millions)**	**Net Derivative Contracts**
Commodity Contracts (in equivalent MWh):			
Power[1]	(25)	(26)	(51)
Natural gas	(28)	29	1
Fuel oil	2	(3)	(1)
Coal	10	10	20
Interest Rate Contracts (in dollars)[2]	475		475

	Notional Volumes at December 31, 2009		
Derivative Instrument	**Derivative Contract Assets**	**Derivative Contract Liabilities (in millions)**	**Net Derivative Contracts**
Commodity Contracts (in equivalent MWh):			
Power[1]	(82)	38	(44)

Natural gas	(32)	32	
Fuel oil	3	(4)	(1)
Coal	1	(1)	

(1) Includes MWh equivalent of natural gas transactions used to hedge power economically.

(2) Beginning in mid-2013, the notional amount will increase to $500 million.

(b) Fair Value Measurements.

Fair Value Hierarchy and Valuation Techniques. The Company applies recurring fair value measurements to its financial assets and liabilities. In determining fair value, the Company generally uses a market approach and incorporates assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. The fair

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

value measurement inputs the Company uses vary from readily observable prices for exchange-traded instruments to price curves that cannot be validated through external pricing sources. Based on the observability of the inputs used in the valuation techniques, the Company s financial assets and liabilities carried at fair value in the consolidated financial statements are classified as follows:

Level 1: Represents unadjusted quoted market prices in active markets for identical assets or liabilities that are accessible at the measurement date. This category primarily includes natural gas and crude oil futures traded on the NYMEX and swaps cleared against NYMEX prices. The Company s interest bearing funds and available-for-sale and trading securities are also valued using Level 1 inputs.

Level 2: Represents quoted market prices for similar assets or liabilities in active markets, quoted market prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. This category primarily includes non-exchange traded derivatives such as OTC forwards, swaps and options, and certain energy derivative instruments that are cleared and settled through exchanges. This category also includes the Company s interest rate swaps.

Level 3: This category includes the Company s energy derivative instruments whose fair value is estimated based on internally developed models and methodologies utilizing significant inputs that are generally less readily observable from market sources (such as implied volatilities and correlations). The Company s OTC, complex or structured derivative instruments that are transacted in less liquid markets with limited pricing information are included in Level 3. Examples are coal contracts, congestion products, power and natural gas contracts, and options valued using internally developed inputs.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls must be determined based on the lowest level input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and consideration of factors specific to the asset or liability.

The fair value of the Company s derivative contract assets and liabilities is based largely on observable quoted prices from exchanges and unadjusted indicative quoted prices from independent brokers in active markets who regularly facilitate the Company s transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company thinks that these prices represent the best available information for valuation purposes. In determining the fair value of its derivative contract assets and liabilities, the Company uses third-party market pricing where available. For transactions classified in Level 1 of the fair value hierarchy, the Company uses the unadjusted published settled prices on the valuation date. For transactions classified in Level 2 of the fair value hierarchy, the Company values these transactions using indicative quoted prices from independent brokers or other widely-accepted valuation methodologies. Transactions are classified in Level 2 if substantially all (greater than 90%) of the fair value can be corroborated using observable market inputs such as transactable broker quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of the Company s derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for assets and ask prices for liabilities. The quotes that the Company obtains from brokers are non-binding in nature, but are from brokers that typically transact in the market being quoted and are based on their knowledge of market transactions on the valuation date. The Company typically obtains multiple broker quotes on the valuation date for each delivery location that extend for the tenor of its underlying contracts. The number of quotes that the Company can obtain depends on the relative liquidity of the delivery location on the valuation date. If multiple broker quotes are received for a contract, the Company uses an average of the quoted bid or ask prices. If only one broker quote is received for a delivery location and it cannot be validated through other external sources, the Company will assign the quote to a lower level within the fair value hierarchy. In some instances, the Company may combine broker quotes for a liquid delivery hub with broker quotes for the price spread

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between the liquid delivery hub and the delivery location under the contract. The Company also may apply interpolation techniques to value monthly strips if broker quotes are only available on a seasonal or annual basis. The Company performs validation procedures on the broker quotes at least on a monthly basis. The validation procedures include reviewing the quotes for accuracy and comparing them to the Company s internal price curves. In certain instances, the Company may discard a broker quote if it is a clear outlier and multiple other quotes are obtained. At December 31, 2010, the Company obtained broker quotes for 100% of its delivery locations classified in Level 2 of the fair value hierarchy.

Inactive markets are considered to be those markets with few transactions, noncurrent pricing or prices that vary over time or among market makers. The Company s transactions in Level 3 of the fair value hierarchy may involve transactions whereby observable market data, such as broker quotes, are not available for substantially all of the tenor of the contract or the Company is only able to obtain indicative broker quotes that cannot be corroborated by observable market data. In such cases, the Company may apply valuation techniques such as extrapolation and other quantitative methods to determine fair value. Proprietary models may also be used to determine the fair value of the Company s derivative contract assets and liabilities that may be structured or otherwise tailored. The Company s techniques for fair value estimation include assumptions for market prices, correlation and volatility. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. At December 31, 2010, the Company s assets and liabilities classified as Level 3 in the fair value hierarchy represented approximately 3% of its total assets and 9% of its total liabilities measured at fair value.

The fair value of the Company s derivative contract assets and liabilities is also affected by assumptions as to time value, credit risk and non-performance risk. The nominal value of the Company s derivatives is discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of the transaction. Derivative contract assets are reduced to reflect the estimated default risk of counterparties on their contractual obligations to the Company. The counterparty default risk for the Company s overall net position is measured based on published spreads on credit default swaps for its counterparties, where available, or proxies based upon published spreads, applied to its current exposure and potential loss exposure from the financial commitments in the Company s risk management portfolio. The fair value of the Company s derivative contract liabilities is reduced to reflect the estimated risk of default on its contractual obligations to counterparties and is measured based on published default rates of the Company s debt, where available, or proxies based upon published spreads. Credit risk and non-performance risk are calculated with consideration of the Company s master netting agreements with counterparties and its exposure is reduced by cash collateral posted to the Company against these obligations.

See note 5(c) for discussion of the Company s fair value measurements for non-financial assets.

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Fair Value of Derivative Instruments and Certain Other Assets. The fair value measurements of the Company s financial assets and liabilities by class are as follows:

	December 31, 2010			
	Level 1(1)	Level 2(1)(2)	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 1	$ 1,140	$ 6	$ 1,147
Fuel	4	3	37	44
Total Asset Management	5	1,143	43	1,191
Trading Activities	530	385	11	926
Interest Rate Contracts		19		19
Total derivative contract assets	$ 535	$ 1,547	$ 54	$ 2,136
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 12	$ 340	$ 4	$ 356
Fuel	18	2	109	129
Total Asset Management	30	342	113	485
Trading Activities	533	389	9	931
Interest Rate Contracts				
Total derivative contract liabilities	$ 563	$ 731	$ 122	$ 1,416
Interest-bearing funds(3)	$ 2,977	$	$	$ 2,977
Other assets(4)	$ 31	$	$	$ 31

(1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no significant transfers during 2010.

(2) Option contracts comprised less than 7% of the Company s net derivative contract assets.

(3) Represent investments in money market funds and are included in cash and cash equivalents, funds on deposit and other noncurrent assets in the consolidated balance sheet. The Company had $2.385 billion of

interest-bearing funds included in cash and cash equivalents, $425 million included in funds on deposit and $167 million included in other noncurrent assets.

(4) Include $13 million in available-for-sale securities (shares in a public exchange) and $18 million in trading securities (rabbi trust investments (which are comprised of mutual funds) associated with the Company s non-qualified deferred compensation plans for key and highly compensated employees).

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	December 31, 2009			
	Level 1	Level 2	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 2	$ 1,162	$ 14	$ 1,178
Fuel	11	8	7	26
Total Asset Management	13	1,170	21	1,204
Trading Activities	374	415	22	811
Total derivative contract assets	$ 387	$ 1,585	$ 43	$ 2,015
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 11	$ 475	$ 2	$ 488
Fuel	14	1		15
Total Asset Management	25	476	2	503
Trading Activities	368	433	9	810
Total derivative contract liabilities	$ 393	$ 909	$ 11	$ 1,313
Interest-bearing funds(1)	$ 2,121	$	$	$ 2,121

(1) Represent investments in money market funds and are included in cash and cash equivalents, funds on deposit and other noncurrent assets in the consolidated balance sheet. The Company had $1.945 billion of interest-bearing funds included in cash and cash equivalents, $137 million included in funds on deposit and $39 million included in other noncurrent assets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is a reconciliation of changes in fair value of net commodity derivative contract assets and liabilities classified as Level 3 during 2009 and 2010, respectively:

	Net Derivatives Contracts (Level 3)		
	Asset Management	Trading	Total
		(in millions)	
Balance, January 1, 2009 (net asset (liability))	$ 24	$ 22	$ 46
Total gains (losses) realized/unrealized:			
Included in earnings[1]	(58)	(62)	(120)
Purchases, issuances and settlements (net)[2]	54	53	107
Transfers in and out of Level 3[3]	(1)		(1)
Balance, December 31, 2009 (net asset (liability))	19	13	32
Acquired and/or assumed in the Merger	2		2
Total gains (losses) realized/unrealized:			
Included in earnings[1]	36	(49)	(13)
Purchases, issuances and settlements (net)[2]	(165)	39	(126)
Transfers in and out of Level 3[3]	38	(1)	37
Balance, December 31, 2010 (net asset (liability))	$ (70)	$ 2	$ (68)

(1) Reflects the total gains or losses on contracts included in Level 3 at the beginning of each quarterly reporting period and at the end of each quarterly reporting period, and contracts entered into during each quarterly reporting period that remain at the end of each quarterly reporting period. Also reflects the Company s coal agreements that were initially recognized at fair value in the second quarter of 2010.

(2) Represents the total cash settlements of contracts during each quarterly reporting period that existed at the beginning of each quarterly reporting period.

(3) Denotes the total contracts that existed at the beginning of each quarterly reporting period and were still held at the end of each quarterly reporting period that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during each quarterly reporting period. Amounts reflect fair value as of the end of each quarterly reporting period.

The following table presents the amounts included in income related to derivative contract assets and liabilities classified as Level 3:

	2010 Operating Revenues	2010 Cost of Fuel, Electricity and Other Products	2010 Total	2009 Operating Revenues	2009 Cost of Fuel, Electricity and Other Products	2009 Total
			(in millions)			
Gains (losses) included in income	$ (28)	$ (74)	$ (102)	$ (22)	$ 8	$ (14)
Gains (losses) included in income (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at December 31	$ (4)	$ (66)	$ (70)	$ 7	$ 7	$ 14

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Counterparty Credit Concentration Risk.

The Company is exposed to the default risk of the counterparties with which the Company transacts. The Company manages its credit risk by entering into master netting agreements and requiring counterparties to post cash collateral or other credit enhancements based on the net exposure and the credit standing of the counterparty. The Company also has non-collateralized power hedges entered into by GenOn Mid-Atlantic. These transactions are senior unsecured obligations of GenOn Mid-Atlantic and the counterparties and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. The Company s credit reserve on its derivative contract assets was $21 million and $13 million at December 31, 2010 and 2009, respectively.

At December 31, 2010 and 2009, approximately $3 million and $12 million, respectively, of cash collateral posted to the Company by counterparties under master netting agreements was included in accounts payable and accrued liabilities on the consolidated balance sheets.

The Company also monitors counterparty credit concentration risk on both an individual basis and a group counterparty basis. The following tables highlight the credit quality and the balance sheet settlement exposures related to these activities:

	December 31, 2010				
Credit Rating Equivalent	**Gross Exposure Before Collateral(1)**	**Net Exposure Before Collateral(2)**	**Collateral(3)**	**Exposure Net of Collateral**	**% of Net Exposure**
			(dollars in millions)		
Clearing and Exchange	$ 1,078	$ 74	$ 74	$	
Investment Grade:					
Financial institutions	837	729		729	65%
Energy companies	550	299	2	297	27%
Other					
Non-investment Grade:					
Financial institutions					
Energy companies	31	18		18	2%
Other					
No External Ratings:					
Internally-rated investment grade	52	45		45	4%
Internally-rated non-investment grade	34	34	8	26	2%
Not internally rated					
Total	$ 2,582	$ 1,199	$ 84	$ 1,115	100%

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2009				
Credit Rating Equivalent	Gross Exposure Before Collateral(1)	Net Exposure Before Collateral(2)	Collateral(3)	Exposure Net of Collateral	% of Net Exposure
	(dollars in millions)				
Clearing and Exchange	$ 790	$ 96	$ 96	$	
Investment Grade:					
Financial institutions	997	646	12	634	81%
Energy companies	497	125	13	112	14%
Other					
Non-investment Grade:					
Financial institutions					
Energy companies					
Other					
No External Ratings:					
Internally-rated investment grade	34	27		27	4%
Internally-rated non-investment grade	8	8		8	1%
Not internally rated					
Total	$ 2,326	$ 902	$ 121	$ 781	100%

(1) Gross exposure before collateral represents credit exposure, including realized and unrealized transactions, before (a) applying the terms of master netting agreements with counterparties and (b) netting of transactions with clearing brokers and exchanges. The table excludes amounts related to contracts classified as normal purchases/normal sales and non-derivative contractual commitments that are not recorded at fair value in the consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic risk if a counterparty does not perform. Non-performance could have a material adverse effect on the future results of operations, financial condition and cash flows.

(2) Net exposure before collateral represents the credit exposure, including both realized and unrealized transactions, after applying the terms of master netting agreements.

(3) Collateral includes cash and letters of credit received from counterparties.

The Company had credit exposure to three investment grade counterparties at December 31, 2010 and 2009, each representing an exposure of more than 10% of total credit exposure, net of collateral and totaling $716 million and $495 million at December 31, 2010 and 2009, respectively.

(d) GenOn Credit Risk.

The Company s standard industry contracts contain credit-risk-related contingent features such as ratings-related thresholds whereby the Company would be required to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. Additionally, some of the Company s contracts contain adequate assurance language, which is generally subjective in nature, but would most likely require the Company to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. However, as a result of the Company s current credit rating, the Company is typically required to post collateral in the normal course of business to offset either substantially or completely its net liability positions, after applying the terms of master netting agreements. At December 31, 2010, the fair value of the Company s financial instruments with credit-risk-related contingent features in a net liability position was $48 million for which the Company had posted collateral of $34 million, including cash and letters of credit.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition, at December 31, 2010 and 2009, the Company had $107 million and $25 million, respectively, of cash collateral posted with counterparties under master netting agreements that was included in funds on deposit on the consolidated balance sheets.

(e) Fair Values of Other Financial Instruments.

The fair values of certain funds on deposit, accounts receivable, notes and other receivables, and accounts payable and accrued liabilities approximate their carrying amounts.

The carrying amounts and fair values of the Company s financial instruments are as follows:

	December 31,			
	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Liabilities:				
Long and short-term debt[1]	$ 6,081	$ 6,095	$ 2,631	$ 2,559

(1) The fair value of the Company s long- and short-term debt is estimated using quoted market prices, when available.

5. Long-Lived Assets

(a) Property, Plant and Equipment, Net.

Property, plant and equipment, net consisted of the following:

	December 31,		Depreciable Lives (years)[1]
	2010	2009	
	(in millions)		
Production	$ 5,613	$ 2,689	3 to 54
Leasehold improvements on leased generating facilities	1,212	1,329	5 to 34
Construction work in progress	172	223	
Other	278	249	2 to 29
Total	7,275	4,490	
Accumulated depreciation and amortization	(977)	(857)	
Total property, plant and equipment, net	$ 6,298	$ 3,633	

(1) The Company completed a depreciation study in the first quarter of 2010 for the legacy Mirant generating facilities that resulted in a change to the estimated useful lives of its long-lived assets. The change in useful lives resulted in an increase of approximately $2 million in depreciation and amortization expense during 2010.

Depreciation of the recorded cost of property, plant and equipment is recognized on a straight-line basis over the estimated useful lives of the assets. Emissions allowances purchased in acquisitions prior to the Merger related to owned facilities are included in production assets above and are depreciated on a straight-line basis over the average life of the related generating facilities.

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Depreciation expense was as follows:

	2010	2009 (in millions)	2008
Depreciation expense	$ 212	$ 141	$ 135

(b) Intangible Assets, Net.

The following is a summary of intangible assets:

		December 31, 2010		December 31, 2009	
	Weighted Average Amortization Lives	Gross Carrying Amount	Accumulated Amortization (in millions)	Gross Carrying Amount	Accumulated Amortization
Trading rights	16 years	$ 15	$ (6)	$ 15	$ (4)
Development rights	33 years	13	(2)	54	(12)
Emissions allowances	30 years	120	(29)	149	(39)
Acquired contracts	4 years	37	(7)		
Other intangibles	17 years	7	(4)	14	(6)
Total intangible assets		$ 192	$ (48)	$ 232	$ (61)

Trading rights are intangible assets recognized in connection with asset purchases that represent the Company s ability to generate additional cash flows by incorporating GenOn s trading activities with the acquired generating facilities. See below for information on the 2009 impairment of the trading rights related to the Potrero and Contra Costa generating facilities.

Development rights represent the right to expand capacity at certain acquired generating facilities. The existing infrastructure, including storage facilities, transmission interconnections and fuel delivery systems and contractual rights acquired by GenOn, provide the opportunity to expand or repower certain generating facilities. See below for information on the 2010 impairment of the development rights related to the Dickerson generating facility and the 2009 impairment of the development rights related to the Potrero generating facility.

Emissions allowances primarily represent allowances granted for the leasehold baseload units at the Dickerson and Morgantown generating facilities. This category also includes $13 million of emissions allowances acquired in connection with the Merger. These emissions allowances were recorded at fair value on the Merger date. See below for information on the 2010 impairment of emissions allowances related to the Dickerson generating facility.

Acquired contracts represent contracts acquired in connection with the Merger and represent the fair value on the Merger date of certain long-term tolling contracts, long-term natural gas transportation and storage contracts and REMA leases. The acquired contracts with positive fair values on the Merger date were recorded in intangible assets and the acquired contracts with negative fair values (out-of-market contracts) on the Merger date were recorded in other long-term liabilities in the consolidated balance sheet. At December 31, 2010, $324 million was included in other long-term liabilities related to out-of-market contracts. The acquired contracts and out-of-market contracts are amortized in operating revenues, cost of fuel, electricity and other products and operations and maintenance expense, as applicable, based on the nature of the contracts and over their contractual lives.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amortization expense was as follows:

	2010	2009	2008
	(in millions)		
Amortization expense	$ 12	$ 8	$ 9

Assuming no future acquisitions, dispositions or impairments of intangible assets, amortization expense, excluding acquired contracts and out-of-market contracts (see below), is estimated to be approximately the following for each of the next five years (in millions):

2011	$ 12
2012	8
2013	7
2014	6
2015	4

Acquired contracts and out-of-market contracts amortization is estimated to be approximately the following for each of the next five years (increase (decrease), net):

	Operating Revenues	Cost of Fuel, Electricity and Other Products	Operations and Maintenance Expense
		(in millions)	
2011	$ (23)	$ (42)	$ (8)
2012	(11)	(35)	(8)
2013		(14)	(8)
2014		(9)	(8)
2015		(8)	(8)

(c) Impairments on Assets Held and Used.

2010

GenOn Mid-Atlantic Generating Facilities

Background

GenOn has goodwill recorded at its GenOn Mid-Atlantic registrant on its standalone balance sheet, which is eliminated upon consolidation at GenOn North America. In accordance with accounting guidance for goodwill and other intangible assets, GenOn is required to test the goodwill balance at GenOn Mid-Atlantic at least annually. GenOn performed the goodwill assessment at October 31, 2010, which, by policy, is the annual testing date. In conducting step one of the goodwill impairment analysis for GenOn Mid-Atlantic, GenOn noted that the carrying value of its net assets exceeded the calculated fair value of GenOn Mid-Atlantic, indicating that step two of the goodwill impairment analysis was required. Based on the results of the step one goodwill impairment analysis, GenOn tested GenOn Mid-Atlantic s long-lived assets for impairment under the accounting guidance related to impairment of long-lived assets before completion of the step two test for goodwill. Upon completion of the assessment, GenOn determined that none of the GenOn Mid-Atlantic generating facilities was impaired at October 31, 2010.

In December 2010, PJM published an updated load forecast, which depicted a decrease in the expected demand from price projections because of lower economic growth expectations. As a result of the load forecast, GenOn s current expectation is that there will be a decrease in the clearing prices for future capacity auctions in certain years. The decrease in projected capacity revenue caused GenOn to update its October 2010 impairment review of GenOn Mid-Atlantic s long-lived assets. Upon completion of the assessment,

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

which was based on the accounting guidance related to the impairment of long-lived assets, GenOn determined that the Dickerson and Potomac River generating facilities were impaired at December 31, 2010, as the carrying value exceeded the updated December 2010 undiscounted cash flows. The Company determined that no other GenOn Mid-Atlantic long-lived assets were impaired at December 31, 2010.

Asset Grouping

For purposes of impairment testing, a long-lived asset or assets must be grouped at the lowest level of identifiable cash flows. Each of the GenOn Mid-Atlantic generating facilities is viewed as an individual asset group. The asset groups also include construction work-in-process, capitalized interest recorded at GenOn North America related to the generating facilities and related intangible assets, including development rights and emissions allowances.

Assumptions and Results

GenOn s assessment of the GenOn Mid-Atlantic generating facilities in the fourth quarter of 2010 included assumptions about the following:

electricity, fuel and emissions prices;

capacity payments under the RPM provisions of PJM s tariff;

costs related to the Montgomery County CO_2 emissions levy (Dickerson generating facility);

costs of CO_2 allowances under a potential federal cap-and-trade program and other environmental regulations;

timing of announced transmission projects;

timing and extent of generating capacity additions and retirements; and

future capital expenditure requirements related to the generating facilities.

GenOn s assumptions related to future electricity and fuel prices were based on observable market prices to the extent available and long-term prices derived from proprietary fundamental market modeling. The long-term capacity prices were based on the assumption that the PJM RPM capacity market would continue consistent with the current structure. For the Dickerson generating facility, the total CO_2 costs under the levy were determined by applying the cost of CO_2 emissions to the expected generation forecasts. GenOn s estimate of future cash flows related to the Dickerson generating facility involved considering scenarios related to the Montgomery County levy. The scenarios are related to the success of the legal challenges to the law. GenOn also assumed for all of the GenOn Mid-Atlantic generating facilities that a federal CO_2 cap-and-trade program would be instituted later this decade which would supplant all pre-existing CO_2 programs, including the Montgomery County levy. In addition, the assumptions included costs associated with compliance of other environmental regulations. There are several transmission projects currently planned in the Mid-Atlantic region, including the Trans-Allegheny Interstate Line (TrAIL), Mid-Atlantic Power Pathway transmission line (MAPP) and the Potomac-Appalachian transmission line (PATH). GenOn s assumptions regarding the timing of these projects were based on the current status of permitting and construction of each project. The assumptions regarding electricity demand were based on forecasts from PJM and assumptions for generating capacity additions and retirements included publicly-announced projects, which take into account renewable sources of electricity. Additionally, GenOn included costs associated with the shutdown of the facility at the end of its estimated useful life and the value associated with the sale of previously granted emissions allowances beyond the shutdown date. Capital expenditures include the remaining contract retention payments for the completion of the Maryland Healthy Air Act pollution control equipment for the Maryland generating facilities. For the Potomac River generating facility, the cash flows also include the remaining $32 million that

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

GenOn Potomac River committed to spend to reduce particulate emissions as part of the agreement with the City of Alexandria, Virginia.

GenOn recorded fourth quarter impairment losses of $523 million and $42 million on the consolidated statement of operations to reduce the carrying values of the Dickerson and Potomac River generating facilities, respectively, to their estimated fair values. In addition, as a result of the impairment of the Potomac River generating facility, GenOn recorded $32 million in operations and maintenance expense and corresponding liabilities associated with its commitment to reduce particulate emissions as part of the agreement with the City of Alexandria, Virginia. The planned capital investment would not be recovered in future periods based on the current projected cash flows of the Potomac River generating facility.

The following table sets forth by level within the fair value hierarchy the Company s assets that were accounted for at fair value on a non-recurring basis. All of the Company s assets that were measured at fair value as a result of impairment losses recorded during the current period were categorized in Level 3 at December 31, 2010:

	Fair Value at December 31, 2010				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total	Loss Included in Earnings
	(in millions)				
Dickerson generating facility	$	$	$ 91	$ 91	$ 462
Dickerson intangible assets			8	8	61
Potomac River generating facility(1)			1	1	42
Total	$	$	$ 100	$ 100	$ 565

(1) The remaining carrying value represents the fair value of the related SO_2 and NO_x emissions allowances included in property, plant and equipment, net.

Dickerson Generating Facility

Background

GenOn also reviewed the Dickerson generating facility for impairment in the second quarter of 2010 upon the enactment of the CO_2 levy by the Montgomery County Council. Upon completion of the assessment, GenOn determined that the Dickerson generating facility was not impaired in the second quarter of 2010.

Bowline Generating Facility

Background

During the second quarter of 2010, the NYISO issued its annual peak load and energy forecast in its Load and Capacity Data report (the Gold Book). The Gold Book reports projected electricity supply and demand for the New York control area for the next ten years. The most recent Gold Book projects a significant decrease in future electricity demand as a result of current economic conditions and the expected future effects of demand-side management programs in New York. The expected reduction in future demand as a result of demand-side management programs is being driven primarily by an energy efficiency program being instituted within the State of New York that will seek to achieve a 15% reduction from 2007 energy volumes by 2015. As a result of the projections in the Gold Book, GenOn evaluated the Bowline generating facility for impairment in the second quarter of 2010. The sum of the probability weighted undiscounted cash flows for

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Bowline generating facility exceeded the carrying value. As a result, GenOn did not record an impairment loss for the Bowline generating facility during the second quarter of 2010.

GenOn Bowline has challenged its property tax assessment for the 2009 and 2010 tax years. Although the assessment for the 2010 tax year was reduced significantly from the assessment received in 2009, the assessment continues to exceed significantly the estimated fair value of the generating facility.

In the fourth quarter of 2010, GenOn identified certain operational issues that reduced the available capacity of the Bowline generating facility. GenOn is in the process of evaluating long-term solutions for the generating facility, but its current expectation is that the reduction in available capacity could extend through 2012. In the fourth quarter of 2010, GenOn again evaluated the Bowline generating facility for impairment because of the expected extended reduction in available capacity together with the pending property tax litigation and the effect of supply and demand assumptions in the NYISO s Gold Book.

Asset Grouping

For purposes of impairment testing, a long-lived asset or assets must be grouped at the lowest level of identifiable cash flows. GenOn included its Hudson Valley Gas subsidiary in the impairment analysis as the sole function of the pipeline operated by Hudson Valley Gas is to supply gas to the Bowline generating facility.

Assumptions and Results

GenOn s assessment for recoverability of the Bowline generating facility under the accounting guidance related to the impairment of a long-lived asset involved developing cash flow projections for the future expected operations of the Bowline generating facility, including scenarios related to the outcome of the ongoing property tax litigation. The cash flow projections included capacity and energy revenue forecasts based on supply and demand assumptions from the NYISO s Gold Book and proprietary fundamental modeling.

The sum of the probability weighted undiscounted cash flows for the Bowline generating facility exceeded the carrying value. As a result, GenOn did not record an impairment loss for the Bowline generating facility during 2010. The carrying value of the Bowline generating facility represented approximately 2% of the Company s total property, plant and equipment, net at December 31, 2010.

Emissions Allowances

In August 2010, the EPA proposed a replacement for the CAIR. The market prices for SO_2 and NO_x emissions allowances declined as a result of the proposed rule. The Company s historical accounting policy has been to include emissions allowances in its asset groupings when evaluating long-lived assets for impairment. However, to the extent the final EPA rule significantly modifies or ends the current cap-and-trade program, the Company may evaluate whether the Company s SO_2 and NO_x emissions allowances included in property, plant and equipment and intangible assets should be evaluated separately from the underlying generating facilities. The carrying value of the SO_2 and NO_x emissions allowances included in property, plant and equipment and intangible assets at December 31, 2010 was $159 million. See Environmental Matters in note 18 for further information on the EPA s proposed replacement of the CAIR.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2009

Potrero Generating Facility

Background

In the third quarter of 2009, GenOn Potrero executed a settlement agreement with the City and County of San Francisco in which it agreed to shut down the Potrero generating facility when it is no longer needed for reliability, as determined by the CAISO. That settlement agreement became effective in November 2009. As a result of the settlement agreement, the Company evaluated the Potrero generating facility for impairment during the third quarter of 2009. In December 2010, the CAISO provided GenOn Potrero with the requisite notice of termination of the RMR agreement. On January 19, 2011, at the request of GenOn Potrero, the FERC approved changes to GenOn Potrero s RMR agreement to allow the CAISO to terminate the RMR agreement effective February 28, 2011. On February 28, 2011, the Potrero facility was shut down. See note 19 for further discussion of the settlement agreement with the City and County of San Francisco.

Asset Grouping

For purposes of impairment testing, a long-lived asset or assets must be grouped at the lowest level of identifiable cash flows. All of the units at GenOn Potrero are viewed as a single asset group. Additionally, the asset group includes intangible assets recorded at GenOn California North for trading and development rights related to GenOn Potrero.

Assumptions and Results

The Company evaluated the Potrero generating facility for impairment during the third quarter of 2009. The Company s assessment of GenOn Potrero under the accounting guidance related to the impairment of a long-lived asset involved developing scenarios for the future expected operations of the Potrero generating facility.

The Company determined that the tangible assets for the Potrero generating facility were not impaired because the weighted average sum of the undiscounted cash flows exceeded the carrying value of the tangible assets in the third quarter of 2009. The Potrero generating facility was fully depreciated at December 31, 2010.

As a result of certain terms included in the settlement agreement, the Company separately evaluated the trading and development rights associated with the Potrero generating facility for impairment and determined that both of these intangible assets were fully impaired as of September 30, 2009. Accordingly, the Company recognized an impairment loss of $9 million on the consolidated statement of operations to write off the carrying value of the intangible assets related to the Potrero generating facility. This impairment loss is included in the results of the Company s California segment for 2009.

Contra Costa Generating Facility

Background

On September 2, 2009, GenOn Delta entered into an agreement with PG&E for the 674 MW Contra Costa units 6 and 7 for the period from November 2011 through April 2013. At the end of the agreement, and subject to any necessary regulatory approval, GenOn Delta has agreed to retire Contra Costa units 6 and 7, which began operations in 1964, in furtherance of state and federal policies to retire aging generating facilities that utilize once-through cooling technology. The agreement to retire these units did not significantly affect the remaining useful life of the Contra Costa generating facility. The GenOn Delta agreement became effective on September 30, 2010.

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Assumptions and Results

The Company evaluated the intangible asset of trading rights related to its Contra Costa generating facility for impairment during the third quarter of 2009 as a result of the shutdown provisions in the tolling agreement. Because the Contra Costa generating facility is under contract with PG&E through its expected shutdown date of April 2013, the Company determined the intangible asset was fully impaired as of September 30, 2009. The Company recorded an impairment loss of $5 million on the consolidated statement of operations to write off the carrying value of the trading rights related to the Contra Costa generating facility. This impairment loss is included in the results of the Company s California segment for 2009.

GenOn Mid-Atlantic Generating Facilities

Background

The Company has goodwill recorded at its GenOn Mid-Atlantic registrant on its standalone balance sheet, which is eliminated upon consolidation at GenOn North America. In accordance with accounting guidance for goodwill and other intangible assets, the Company is required to test the goodwill balance at GenOn Mid-Atlantic at least annually. The Company performed the goodwill assessment at October 31, 2009, which, by policy, is the annual testing date. In conducting step one of the goodwill impairment analysis for GenOn Mid-Atlantic, the Company noted that the carrying value of its net assets exceeded the calculated fair value of GenOn Mid-Atlantic, indicating that step two of the goodwill impairment analysis was required. Based on the results of the step one goodwill impairment analysis, the Company tested GenOn Mid-Atlantic s long-lived assets for impairment under the accounting guidance related to impairment of long-lived assets before completion of the step two test for goodwill. During 2009, the continued decline in average natural gas prices caused power prices to decline in the Eastern PJM region. Additionally, weak economic conditions and various demand-response programs have resulted in a decrease in the forecasted gross margin of the GenOn Mid-Atlantic generating facilities.

Upon completion of the assessment, which was based on the accounting guidance related to the impairment of long-lived assets, the Company determined that the Potomac River generating facility was impaired, as the carrying value exceeded the undiscounted cash flows. In performing the impairment assessment, the Company noted that the undiscounted cash flows for other GenOn Mid-Atlantic generating facilities also decreased significantly from the prior year. The Company determined that no other GenOn Mid-Atlantic long-lived assets were impaired at October 31, 2009.

As a result of the assessment, the Company recorded an impairment loss of $207 million in the fourth quarter of 2009 to reduce the carrying value of the Potomac River generating facility to its estimated fair value.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth by level within the fair value hierarchy the Company s assets that were accounted for at fair value on a non-recurring basis. All of the Company s assets that were measured at fair value as a result of impairment losses recorded during the current period were categorized in Level 3 at December 31, 2009:

	Fair Value at December 31, 2009				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total	Loss Included in Earnings
			(in millions)		
Potomac River generating facility	$	$	$ 37	$ 37	$ 207
Potrero intangible assets					9
Contra Costa intangible assets					5
Total	$	$	$ 37	$ 37	$ 221

(d) Asset Retirement Obligations.

Upon initial recognition of a liability for an asset retirement obligation or a conditional asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of accounting guidance are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company identified certain asset retirement obligations within its power generating facilities. These asset retirement obligations are primarily related to asbestos abatement in facilities on owned or leased property and other environmental obligations related to ash disposal sites. In addition, the asset retirement obligations also relate to environmental obligations for fuel storage facilities, wastewater treatment facilities and pipelines. See note 18 for further discussion of the Company s ash disposal facilities.

Asbestos abatement is the most significant type of asset retirement obligation identified for recognition in connection with the Company s policy related to accounting for conditional asset retirements. The EPA has regulations in place governing the removal of asbestos. Because of the nature of asbestos, it can be difficult to ascertain the extent of contamination in older facilities unless substantial renovation or demolition takes place. Therefore, the Company incorporated certain assumptions based on the relative age and size of its facilities to estimate the current cost for asbestos abatement. The actual abatement cost could differ from the estimates used to measure the asset retirement obligation. As a result, these amounts will be subject to revision when actual abatement activities are undertaken.

During 2010, a third-party consulting firm completed a study on behalf of GenOn to determine the extent of asbestos present at certain of GenOn s generating facilities. The consulting firm also provided GenOn with cost estimates for the removal of the asbestos. As a result, GenOn revised the cost estimates associated with its asset retirement obligations for asbestos removal at all of its generating facilities.

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The following table sets forth the balances of the asset retirement obligations and the additions, revisions in estimated cash flows and accretion of the asset retirement obligations. The asset retirement obligations are included in other noncurrent liabilities in the consolidated balance sheets:

	2010	2009
	(in millions)	
Beginning balance January 1	$ 43	$ 40
Assumed in the Merger	73	
Revisions in estimated cash flows	7	
Accretion expense	5	3
Ending balance December 31	$ 128	$ 43

At December 31, 2010, GenOn had $24 million (classified in other long-term assets) on deposit with the state of Pennsylvania to guarantee its obligation related to future closures of coal ash disposal landfill sites.

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Long-Term Debt

(a) Overview.

Outstanding debt was as follows:

	December 31, 2010			December 31, 2009		
	Weighted Average Stated Interest Rate(1)	Long-term	Current	Weighted Average Stated Interest Rate(1)	Long-term	Current
	(in millions, except interest rates)					
Facilities, Bonds and Notes:						
GenOn:						
Senior secured notes, due 2014(2)	6.75%	$	$ 279		$	$
Senior unsecured notes, due 2014	7.625	575				
Senior unsecured notes, due 2017	7.875	725				
Senior secured term loan, due 2017(3)	6.00	691	7			
Senior unsecured notes, due 2018(4)	9.50	675				
Senior unsecured notes, due 2020(4)	9.875	550				
Unamortized debt discounts		(27)	(2)			
GenOn Americas Generation:						
Senior unsecured notes, due 2011	8.30		535	8.30%	535	
Senior unsecured notes, due 2021	8.50	450		8.50	450	
Senior unsecured notes, due 2031	9.125	400		9.125	400	
Unamortized debt discounts, net		(2)			(3)	
GenOn North America:						
Senior secured term loan				2.13	303	70
Senior notes, due 2013(5)	7.375		850	7.375	850	
Other:						

Capital leases, due 2011 to 2015	7.375-8.19	18	4	7.375-8.19	21	5
PEDFA fixed-rate bonds, due 2036(6)	6.75		371			
Adjustment to fair value of debt(7)		(32)	14			
Total		$ 4,023	$ 2,058		$ 2,556	$ 75

(1) The weighted average stated interest rates are at December 31, 2010 and 2009.

(2) These notes were discharged at the closing of the Merger on December 3, 2010 and were redeemed on January 3, 2011 at a call price of 102.25% of the principal amount.

(3) The debt balance on the term loan facility is recorded at GenOn Americas, a direct subsidiary of GenOn Energy Holdings, because GenOn Americas is a co-borrower.

(4) Effective interest rates of 9.87% and 10.2% for senior unsecured notes due 2018 and 2020, respectively.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) These notes were discharged at the closing of the Merger on December 3, 2010 and were redeemed on January 3, 2011 at a call price of 101.844% of the principal amount.

(6) These notes were defeased at 103% of principal plus accrued and unpaid interest to the redemption date in June 2011. The Company expects to redeem these notes when they become redeemable in June 2011.

(7) Debt assumed in the Merger was adjusted to fair value on the Merger date. See note 2. Included in interest expense during 2010 is an insignificant amount of amortization expense for valuation adjustments related to the assumed debt.

Debt maturities for the principal amounts at December 31, 2010 are (in millions):

2011	$ 2,046(1)
2012	11
2013	11
2014	587
2015	12
2016 and thereafter	3,463
Total	$ 6,130

(1) Includes (a) $279 million of GenOn Energy senior secured notes and $850 million of GenOn North America senior notes redeemed on January 3, 2011 and (b) $371 million of PEDFA fixed-rate bonds which will be redeemed in June 2011.

(b) Debt Financing Transactions Related to the Merger.

Debt Issuances:

Senior Secured Term Loan Facility and Revolving Credit Facility

On September 20, 2010, GenOn entered into a credit agreement, which provides for:

- a $700 million seven-year senior secured term loan facility with a rate of LIBOR + 4.25% (with a LIBOR floor of 1.75%); and

- a $788 million five-year senior secured revolving credit facility, with an undrawn rate of 0.75% and a drawn rate of LIBOR + 3.50%.

The Company refers to the new revolving facility and new term loan facility collectively as the GenOn credit facilities. The term loan facility was funded at the close of the Merger on December 3, 2010. Although $275 million of outstanding letters of credit were transferred from pre-merger credit facilities, GenOn did not make any borrowings under the revolving credit facility at closing.

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At December 31, 2010, outstanding letters of credit were $267 million and availability of borrowings under the revolving credit facility was $521 million.

The senior secured term loan will amortize in quarterly installments of 0.25% of the original principal of the term loan for the first 27 quarters, with the remainder payable on the final maturity date. The first amortization payment of $2 million was paid on December 31, 2010.

Loans under the GenOn credit facilities are available at either of the following rates: (a) the base rate plus the applicable margin or (b) the LIBOR rate plus the applicable margin. The applicable margin with respect to loans under the GenOn senior secured revolving credit facility is 2.5% in the case of base rate loans, or 3.5% in the case of LIBOR rate loans. The applicable margin with respect to loans under the senior secured

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

term loan is 3.25% in the case of base rate loans, or 4.25% in the case of LIBOR rate loans. For the term loan facility only, the LIBOR rate shall not be less than 1.75% per annum. In addition, the term loan facility also accrued interest at 4.25% per annum during the period between the commitment date of September 20, 2010 and the date that the term loan was funded, which amounts were paid upon funding.

The terms of the GenOn credit facilities require GenOn to maintain a ratio of consolidated secured debt (net of up to $500 million in cash) to adjusted EBITDA of not more than 3.50 to 1.00, which will be tested at the end of each fiscal quarter and, in the case of EBITDA, will be calculated on a rolling four quarter basis ending on the last day of such fiscal quarter. At December 31, 2010, the Company was in compliance with the debt covenants. In addition, the GenOn credit facilities restrict the ability of GenOn to, among other things, (a) incur additional indebtedness, (b) pay dividends, prepay subordinated indebtedness or purchase capital stock, (c) encumber assets, (d) enter into business combinations or divest assets, (e) make investments or loans, (f) enter into transactions with affiliates and (g) engage in sale and leaseback transactions, subject in each case to certain exceptions or excluded amounts. The GenOn credit facilities provide for acceleration of GenOn s obligations and the termination of commitments thereunder upon the occurrence and continuance of certain events of default, including, without limitation: (a) failure to pay principal when due, (b) failure to pay for a period of five business days interest and other amounts when due, (c) default in the performance of certain covenants contained in the credit agreement, subject to grace or cure periods set forth therein, (d) failure to pay amounts due, after applicable grace periods, under, or upon acceleration of, certain material debt, (e) any money judgment rendered against us which is not stayed for any period of 60 days, (f) any change of control (as defined in the GenOn credit agreement) and (g) certain bankruptcy and insolvency events.

The GenOn credit facilities, and the subsidiary guarantees thereof, are the senior secured obligations of GenOn and certain of its existing and future direct and indirect subsidiaries, excluding GenOn Americas Generation; provided, however, that certain of GenOn Americas Generation s subsidiaries (other than GenOn Mid-Atlantic and GenOn Energy Management and their subsidiaries) guarantee the GenOn credit facilities to the extent permitted under the indenture for the senior notes of GenOn Americas Generation. GenOn Americas became a co-borrower under the GenOn credit facilities upon the closing of the Merger.

Senior Unsecured Notes, Due 2018 and 2020

On October 4, 2010, GenOn Escrow issued two series of senior unsecured notes:

$675 million of 9.5% senior notes due 2018; and

$550 million of 9.875% senior notes due 2020.

The senior notes were issued at a discount to par, resulting in net proceeds to GenOn Escrow of $1.2 billion. Upon completion of the Merger, GenOn Escrow merged with and into GenOn which assumed all of GenOn Escrow s obligations under the notes and the related indenture and the funds held in escrow were released to GenOn.

The senior notes and the related indentures restrict the ability of GenOn to incur additional liens and make certain restricted payments, including dividends and purchases of capital stock. At December 31, 2010, GenOn did not meet the consolidated debt ratio component of the restricted payments test and, therefore, the ability of GenOn to make restricted payments is limited to specified exclusions from the covenant, including up to $250 million of such restricted payments. In the event of a change of control of GenOn, holders of the senior notes have the right to require

GenOn to purchase the outstanding senior notes at a price equal to 101% of the principal amount plus accrued and unpaid interest and additional interest (as defined in the indenture), if any. The senior notes will be subject to acceleration of GenOn s obligations thereunder upon the occurrence of certain events of default, including: (a) default in interest payment for 30 days, (b) default in the payment of principal or premium, if any, (c) failure after 90 days of specified notice to comply with any other agreements in the indenture, (d) certain cross-acceleration events, (e) failure by GenOn or its significant

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

subsidiaries to pay certain final and non-appealable judgments after 90 days and (f) certain events of bankruptcy and insolvency.

Under the senior notes and the related indentures, the senior notes are the sole obligation of GenOn and are not guaranteed by any subsidiary of GenOn.

Discharge, Defeasance, Redemption and Repayment of Debt:

GenOn Senior Secured Notes Due 2014

The senior secured notes due 2014 of GenOn (issued in 2004) were recorded at their fair value on the Merger date which approximated their redemption value. Upon closing of the Merger, the senior secured notes were discharged following the deposit with the trustee of funds sufficient to pay the redemption price thereof, plus accrued interest to the date of redemption. The amount of funds on deposit with the trustee was $285 million at December 31, 2010 and is recorded as restricted cash and included in funds on deposit on the consolidated balance sheet.

On January 3, 2011, the senior secured notes were redeemed at the call price of 102.25% of the principal amount plus accrued and unpaid interest through the date of redemption. The total payment on the date of redemption was $285 million.

GenOn North America Senior Secured Credit Facilities

Upon closing of the Merger, GenOn North America repaid the outstanding senior secured credit facility (entered into in 2006) of $305 million plus accrued and unpaid interest through the date of repayment. The total payment was $305 million and a $9 million loss on extinguishment of debt was recognized in other, net in the consolidated statement of operations. Letters of credit in the amount of $197 million outstanding under the GenOn North America credit facilities were transferred to the GenOn revolving credit facility and $124 million of the cash collateral previously posted to support these letters of credit was released to fund a portion of the Merger closing costs.

GenOn North America Senior Notes Due 2013

Upon closing of the Merger, the senior secured notes due 2013 of GenOn North America (issued in 2005) were discharged following the deposit with the trustee of funds sufficient to pay the redemption price thereof, plus accrued interest to the date of redemption. The amount of funds on deposit with the trustee was $866 million at December 31, 2010 and is recorded as restricted cash, included in funds on deposit on the consolidated balance sheet.

On January 3, 2011, the senior secured notes were redeemed at the call price of 101.844% of the principal amount plus accrued and unpaid interest through the date of redemption. The total payment on the date of redemption was $866 million and a $23 million loss on extinguishment of debt was recognized in 2011, which includes a $16 million premium and $7 million of unamortized debt issuance costs.

PEDFA Fixed-Rate Bonds

The PEDFA bonds (issued in 2004) were recorded at their fair value on the Merger date which approximated their redemption value. Upon closing of the merger, GenOn completed a defeasance of the PEDFA bonds (which are classified as current debt obligations at December 31, 2010) by depositing sufficient funds with the trustee solely to satisfy the principal plus 3% premium and accrued interest to the date of redemption. The amount of funds on deposit with the trustee was $394 million at December 31, 2010 and is recorded as restricted cash, included in funds on deposit on the consolidated balance sheet.

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The Company has delivered the required notices to redeem the PEDFA bonds in June 2011, the earliest date that they can be redeemed.

(c) Credit Facility, Debt and Capital Leases.

GenOn Marsh Landing Credit Facility

On October 8, 2010, GenOn Marsh Landing entered into a credit agreement for up to approximately $650 million of commitments to provide construction and permanent financing for the Marsh Landing generating facility. The credit facility consists of a $155 million tranche A senior secured term loan facility, a $345 million tranche B senior secured term loan facility, a $50 million senior secured letter of credit facility to support GenOn Marsh Landing s debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing s collateral requirements under its PPA with PG&E. The term loans will be available to be drawn during the construction of the project upon the satisfaction of the conditions precedent thereto, including the receipt by GenOn Marsh Landing of base equity contributions of $147 million. Prior to the commercial operation date of the project, the collateral requirements under the PPA and construction contracts are being met by a $165 million cash collateralized letter of credit facility entered into by GenOn Energy Holdings on behalf of GenOn Marsh Landing on September 27, 2010. At or near the commercial operation date of the project those collateral requirements will terminate. At December 31, 2010, GenOn Marsh Landing had not drawn on its credit facility.

The term loans are to be fully amortized by their maturity dates. The tranche A term loan matures on December 31, 2017 and the tranche B term loan matures on the date that is the earlier of the last day of the first fiscal quarter following the tenth anniversary of the conversion of the credit facility from a construction facility to a permanent facility upon commercial operation of the Marsh Landing project and December 31, 2023. The expiry date of the letters of credit is December 31, 2017. Interest on the tranche A term loans will be based on a base rate or a LIBOR rate plus an initial applicable margin of 1.5% for base rate loans and 2.5% for LIBOR loans (with such margin increasing 0.25% every three years). Interest on the tranche B term loans will be based on a base rate or a LIBOR rate plus an initial applicable margin of 1.75% for base rate loans and 2.75% for LIBOR loans (with such margin increasing 0.25% every three years). Fees on lenders exposure under the letters of credit accrue at a rate equal to the applicable margin payable on the tranche A term loans that are based on the LIBOR rate. An undrawn commitment fee applies at a rate of 0.75%.

In connection with the credit agreement, GenOn Marsh Landing entered into interest rate swaps to mitigate the interest rate risks with respect to the term loan. GenOn Energy Holdings provided limited guarantees in respect of the interest rate swaps. The effective interest rate that GenOn Marsh Landing will pay for the term loan from the commercial operations date is 5.91% (plus the step-up in margin over time). The interest rate swaps will be accounted for as cash flow hedges with changes in fair value recognized in other comprehensive income, with the exception of any ineffectiveness which will be recognized in the consolidated statement of operations. GenOn expects the interest rate swaps to remain highly effective in mitigating the interest rate risk.

Loans under the credit facility will be subject to mandatory prepayment upon the occurrence of certain events, including an event of damage or an event of taking, the receipt of the proceeds of any claim under any document executed in connection with the Marsh Landing project and any amounts payable as a result of termination of the PPA. The credit facility includes customary affirmative and negative covenants and events of default. Negative covenants include limitations on additional debt, liens, negative pledges, investments, distributions, business activities, stock repurchases, asset dispositions, accounting changes, change orders and affiliate transactions. Events of default include non-performance of covenants, breach of representations, cross-acceleration of other material indebtedness, bankruptcy and insolvency, undischarged material judgments, a change in control and a failure to achieve commercial operation of the Marsh Landing project by December 31, 2013.

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GenOn Americas Generation Senior Notes

The senior notes due 2011, 2021 and 2031 are senior unsecured obligations of GenOn Americas Generation having no recourse to any subsidiary or affiliate of GenOn Americas Generation. The principal balance of the GenOn Americas Generation senior notes due in May 2011 is included in current portion of long-term debt at December 31, 2010. During 2008, GenOn purchased and retired $276 million of GenOn Americas Generation senior notes due in 2011.

GenOn Senior Unsecured Notes, Due 2014 and 2017

The senior notes due 2014 and 2017 of GenOn were recorded at their fair values of $582 million and $683 million, respectively, on the Merger date. The $7 million premium and $42 million discount are being amortized to interest expense over the life of the related notes. The senior notes are senior unsecured obligations of GenOn having no recourse to any subsidiary or affiliate of GenOn. The senior notes restrict the ability of GenOn and its subsidiaries to encumber their assets.

Capital Leases

Outstanding debt includes a capital lease by GenOn Chalk Point. At December 31, 2010 and 2009, the current portion of the long-term debt under this capital lease was $4 million. The amount outstanding under the capital lease at December 31, 2010, which matures in 2015, is $22 million with an 8.19% annual interest rate. This lease is for an 84 MW peaking electric power generating facility. Depreciation expense related to this lease was $2 million during 2010, 2009 and 2008. The annual principal payments under this lease are $4 million in 2011, 2012 and 2013, and $5 million in 2014 and 2015. The gross amount of assets under the capital lease, recorded in property, plant and equipment, net, was $24 million at December 31, 2010 and 2009. The related accumulated depreciation was $16 million and $15 million at December 31, 2010 and 2009, respectively.

(d) Sources of Funds.

The principal sources of liquidity for the Company are expected to be: (a) existing cash on hand and expected cash flows from the operations of the Company s subsidiaries, (b) letters of credit issued or borrowings made under the GenOn revolving credit facility and (c) letters of credit issued or borrowings made under GenOn Marsh Landing s project financing.

The Company and certain of its subsidiaries are holding companies and, as a result, the Company and such subsidiaries are dependent upon dividends, distributions and other payments from their respective subsidiaries to generate the funds necessary to meet their obligations. In particular, a substantial portion of the cash from the Company s operations is generated by GenOn Mid-Atlantic. The ability of certain of the Company s subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements, including the operating leases of GenOn Mid-Atlantic and REMA. Under their respective operating leases, GenOn Mid-Atlantic and REMA are not permitted to make any distributions and other restricted payments unless: (a) they satisfy the fixed charge coverage ratio for the most recently ended period of four fiscal quarters; (b) they are projected to satisfy the fixed charge coverage ratio for each of the two following periods of four fiscal quarters, commencing with the fiscal quarter in which such payment is proposed to be made; and (c) no significant lease default or event of default has occurred and is continuing. In the event of a default under the respective operating leases or if the respective restricted payment tests are not satisfied, GenOn Mid-Atlantic and REMA would not be able to distribute cash. At

December 31, 2010, GenOn Mid-Atlantic and REMA satisfied the respective restricted payments tests.

Pursuant to the terms of their respective lease and debt documents, GenOn Mid-Atlantic, REMA and GenOn Marsh Landing are restricted from, among other actions, (a) encumbering assets, (b) entering into

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

business combinations or divesting assets, (c)incurring additional debt, (d) entering into transactions with affiliates on other than an arm s length basis or (e) materially changing their business. Therefore, at December 31, 2010, all of GenOn Mid-Atlantic s net assets (excluding cash) and all of REMA s net assets (excluding cash) were deemed restricted for purposes of Rule 4-08(e)(3)(iii) of Regulation S-X.

The amounts of restricted net assets were as follows:

	December 31, 2010 (in millions)	December 31, 2009 (in millions)
GenOn Mid-Atlantic	$ 3,698	$ 4,761
REMA	303	
GenOn Marsh Landing	80	6
Total restricted net assets	$ 4,081	$ 4,767

The ability of GenOn Americas Generation to pay its obligations is dependent on the receipt of dividends from GenOn North America, capital contributions or intercompany loans from GenOn and its ability to refinance all or a portion of those obligations as they become due. Although the Company continues to evaluate its refinancing options, the Company expects to maintain adequate liquidity to retire the GenOn Americas Generation senior notes that come due in May 2011.

7. Income Taxes

Income (loss) from continuing operations before income taxes during 2010, 2009 and 2008 was $(52) million, $506 million and $1.2 billion, respectively.

The income tax provision from continuing operations consisted of the following:

	2010 (in millions)	2009 (in millions)	2008 (in millions)
Current income tax provision (benefit)	$ (2)	$ 12	$ 2
Deferred income tax provision			
Provision (benefit) for income taxes	$ (2)	$ 12	$ 2

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A reconciliation of the Company s federal statutory income tax provision to the effective income tax provision/benefit adjusted for permanent and other items during 2010, 2009 and 2008, is as follows:

	2010	2009 (in millions)	2008
Provision for income taxes based on United States federal statutory income tax rate	$ (18)	$ 177	$ 426
State and local income tax provision, net of federal income taxes	2	29	119
Merger-related write-off of NOL and state and local income tax provision, net of federal income taxes	168		
Merger-related write-off of NOL and other deferred tax assets	748		
Merger-related costs	24		
Effect of equity-related transactions	22	13	(35)
Reorganization adjustments	2	(21)	
Excess tax deductions related to bankruptcy transactions		(17)	
Change in deferred tax asset valuation allowance	(772)	(170)	(528)
Gain on bargain purchase	(181)		
Discontinued operations			18
Other differences, net	3	1	2
Tax provision (benefit)	$ (2)	$ 12	$ 2

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their respective tax bases which give rise to deferred tax assets and liabilities for continuing operations are as follows:

	December 31, 2010	December 31, 2009
	(in millions)	
Deferred Tax Assets:		
Employee benefits	$ 140	$ 82
Reserves	28	14
Loss carryforwards	928	1,167
Property and intangible assets	553	74
Other	80	56
Subtotal	1,729	1,393
Valuation allowance[1]	(1,559)	(1,088)
Net deferred tax assets	170	305

Deferred Tax Liabilities:		
Derivative contracts	(144)	(281)
Other	(26)	(24)
Net deferred tax liabilities	(170)	(305)
Net deferred taxes[(1)]	$	$

(1) The Company acquired $1,243 million of NOLs and other net deferred tax assets, before a complete offset by valuation allowances, of RRI Energy as a result of the Merger.

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NOLs

As a result of the Merger, each of Mirant and RRI Energy has separately determined whether or not each had experienced an ownership change as defined in the IRC. IRC Section (IRC §) 382 provides, in general, that an ownership change occurs when there is a greater than 50-percentage point increase in ownership of a company s stock by new or existing stockholders who own (or are deemed to own under IRC § 382) 5% or more of the loss company s stock over a three year testing period. IRC § 382 limits the amount of pre-merger NOLs that can be used during any post-ownership change year to offset taxable income. Prior to the Merger, the Company evaluated whether RRI Energy experienced an ownership change as defined above. RRI Energy received guidance from the Internal Revenue Service that specifies the methodology to be used in determining whether an ownership change has occurred under circumstances when a stockholder owns interests in each of the merging companies immediately prior to the Merger. The Company has determined that there were sufficient overlapping stockholders of Mirant and RRI Energy immediately prior to the Merger such that the Merger did not cause an ownership change for RRI Energy. Therefore, RRI Energy s pre-merger NOLs have not been adjusted for any IRC § 382 limitation.

Mirant experienced an ownership change as a result of the Merger and the Company reduced by $2.1 billion the amount of the Mirant federal NOLs that would have been available to offset post-merger taxable income based on a $54 million annual limit determined in accordance with IRC § 382. The Company has also reduced its state NOLs by $2.5 billion for state jurisdictions that also follow IRC § 382.

At December 31, 2010, the Company s federal NOL carryforward for financial reporting was $1.9 billion with expiration dates from 2022 to 2030. Similarly, there is an aggregate amount of $4.8 billion of state NOL carryforwards with various expiration dates (based on the Company s review of the application of apportionment factors and other state tax limitations).

The guidance related to accounting for income taxes requires that a valuation allowance be established when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences are deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including the Company s past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. The Company evaluates this position quarterly and makes its judgment based on the facts and circumstances at that time. The Company has determined that primarily as a result of significant declines in demand, power and natural gas prices remaining low compared to several years ago and the effect of these lower prices on its projected gross margin, the realization of future taxable income sufficient to utilize existing deferred tax assets is not more-likely-than not at this time.

At December 31, 2010, the Company s deferred tax assets reduced by the valuation allowance are completely offset by its deferred tax liabilities. Additionally, the Company s valuation allowance includes $17 million relating to the tax effects of other comprehensive income items primarily related to employee benefits. These other comprehensive income items will be reduced in the event that the valuation allowance is no longer required.

Tax Uncertainties

The recognition of contingent losses for tax uncertainties requires management to make significant assumptions about the expected outcomes of certain tax contingencies. Under the accounting guidance, the Company must reflect in its income tax provision the full benefit of all positions that will be taken in the

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s income tax returns, except to the extent that such positions are uncertain and fall below the benefit recognition requirements. In the event that the Company determines that a tax position meets the uncertainty criteria, an additional liability or an adjustment to the Company s NOLs, determined under the measurement criteria, will result. The Company periodically reassesses the tax positions in its tax returns for open years based on the latest information available and determines whether any portion of the tax benefits reflected should be treated as unrecognized. A reconciliation of the beginning and ending amount of unrecognized tax benefits for continuing operations is as follows:

	2010	2009
	(in millions)	
Unrecognized tax benefits, January 1	$ 13	$ 13
Increases based on tax positions related to the current year		3
Settlements	(2)	(3)
Decrease as a result of IRC § 382	(12)	
Assumed in the Merger	11	
Unrecognized tax benefits, December 31	$ 10	$ 13

The unrecognized tax benefits included the review of tax positions relating to open tax years beginning in 2002 and continuing to the present. The Company s major tax jurisdictions are the United States at the federal level and multiple state and local jurisdictions. For United States federal and state income taxes, tax years are open subsequent to 2001. However, both the federal and state NOL carryforwards from any closed year are subject to examination until the year that such NOL carryforwards are utilized and that utilization year is closed for audit. The Company has reduced the unrecognized tax benefits during 2010 as a result of the ownership change, as defined in IRC § 382, resulting from the Merger. The ownership change resulted in the write-off of NOLs and the related write-off of the unrecognized tax benefits. The Company does not anticipate any significant changes in its unrecognized tax benefits over the next 12 months. The Company has not recognized any tax benefits for certain filing positions for which the outcome is uncertain and the effect is estimable.

Included in the balance at December 31, 2010 and 2009, the Company had $6 million and $1 million, respectively, of unrecognized tax benefits that would affect the effective tax rate if they were recognized. The Company s tax provision includes an immaterial amount related to the accrual for any penalties and interest subsequent to its adoption of the accounting guidance related to accounting for uncertainty in income taxes. The amounts recorded in the Company s consolidated balance sheet for interest and penalties related to the unrecognized tax benefits at December 31, 2010 and 2009 are $2 million and $0, respectively.

The Company continues to be under audit for multiple years by taxing authorities in various jurisdictions. Considerable judgment is required to determine the tax treatment of particular items that involve interpretations of complex tax laws. A tax liability is recorded for filing positions with respect to which the outcome is uncertain and the recognition criteria under the accounting guidance for uncertainty in income taxes has been met. Such liabilities are based on judgment and it can take many years to resolve a recorded liability such that the related filing position is no longer subject to question. The Company has not recorded a liability for those proposed tax adjustments related to the current tax audits when it continues to think that its filing position meets the more-likely-than-not threshold prescribed in the accounting guidance related to accounting for uncertainty in income taxes. Any adverse outcomes arising from these matters could result in a material change in the amount of the Company s deferred taxes.

The Company ceased being a member of the CenterPoint consolidated tax group at September 30, 2002 and could be limited in the Company s ability to use tax attributes generated during periods through that date. The Internal Revenue Service s audits of CenterPoint s federal income tax returns for the 1997 to 2002 tax reporting periods have been closed, subject to a review by the Internal Revenue Service of certain claims

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

formally submitted by the Company for the 2002 tax year. The Company has a tax allocation agreement that addresses the allocation of taxes pertaining to the Company s separation from CenterPoint. This agreement provides that the Company may carry back net operating losses generated subsequent to September 30, 2002 to tax years when it was part of CenterPoint s consolidated tax group. Any such carryback is subject to CenterPoint s consent and any existing statutory carryback limitations. For items relating to periods prior to September 30, 2002, the Company will (a) recognize any net costs incurred by CenterPoint for settlement of temporary differences up to $15 million (of which $0 had been recognized through December 31, 2010 and 2009) as an equity contribution and (b) recognize any net benefits realized by CenterPoint for settlement of temporary differences up to $1 million as an equity distribution. Generally, amounts for temporary differences in excess of the $15 million and $1 million thresholds will be settled in cash between the Company and CenterPoint. Pursuant to this agreement, generally, taxes related to permanent differences are the responsibility of CenterPoint. As of December 31, 2010, the Company cannot predict the amount of any contingent liabilities or assets that the Company may incur or realize under this agreement.

8. Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

Benefit Plans

The Company provides pension benefits to its eligible non-union and union employees through various defined benefit and defined contribution pension plans. These benefits are based on pay, service history and age at retirement. Defined benefit pensions are not provided for non-union employees hired after April 1, 2000, who participate in the Company s profit sharing arrangement. Most pension benefits are provided through tax-qualified plans that are funded in accordance with the Employee Retirement Income Security Act of 1974 and Internal Revenue Service requirements. Certain executive pension benefits that cannot be provided by the tax-qualified plans are provided through unfunded non-tax-qualified plans. The measurement date for the defined benefit plans was December 31 for all periods presented.

The Company also provides certain medical care and life insurance benefits for eligible retired employees which are accounted for on an accrual basis using an actuarial method that recognizes the net periodic costs as employees render service to earn the postretirement benefits. The measurement date for these postretirement benefit plans was December 31 for all periods presented.

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The following table shows the benefit obligations and funded status for the defined benefit pension and other postretirement benefit plans:

	Tax-Qualified Pension Plans		Non-Tax-Qualified Pension Plans		Other Postretirement Benefit Plans	
	2010	2009	2010	2009	2010	2009
			(in millions)			
Change in benefit obligation:						
Benefit obligation, January 1	$ 291	$ 286	$ 9	$ 9	$ 57	$ 62
Obligations assumed in the Merger	129				68	
Service cost	8	8			1	2
Interest cost	17	15	1	1	2	3
Amendments		1				(2)
Benefits paid	(11)	(9)	(1)	(1)	(1)	(2)
Curtailments					(48)	
Actuarial (gain) loss	14	(10)	1		(1)	(6)
Benefit obligation, December 31	$ 448	$ 291	$ 10	$ 9	$ 78	$ 57
Change in plan assets:						
Fair value of plan assets, January 1	$ 240	$ 206	$	$	$	$
Assets acquired in the Merger	92					
Return on plan assets	37	43				
Employer contributions	1		1	1	2	2
Benefits paid	(11)	(9)	(1)	(1)	(2)	(2)
Fair value of plan assets, December 31	$ 359	$ 240	$	$	$	$
Funded Status:						
Underfunded at measurement date	$ (89)	$ (51)	$ (10)	$ (9)	$ (78)	$ (57)

Amounts recognized in the consolidated balance sheets for pensions and other postretirement benefit plan obligations at December 31, 2010 and 2009 are:

	Tax-Qualified Pension Plans		Non-Tax Qualified Pension Plans		Other Postretirement Benefit Plans	
	2010	2009	2010	2009	2010	2009
			(in millions)			

Current liabilities	$		$		$	(1)	$	(1)	$	(5)	$	(3)
Noncurrent liabilities		(89)		(51)		(9)		(8)		(73)		(54)
Total liabilities	$	(89)	$	(51)	$	(10)	$	(9)	$	(78)	$	(57)

The accumulated benefit obligation exceeded the fair value of plan assets at December 31, 2010 and 2009 for the tax qualified pension plans. The total accumulated benefit obligation for the tax qualified plan at December 31, 2010 and 2009 was $413 million and $259 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amounts recognized in other comprehensive income/loss and accumulated other comprehensive loss for the defined benefit pension and other postretirement benefit plans are:

	Tax-Qualified Pension Plans		Non-Tax-Qualified Pension Plans		Other Postretirement Benefit Plans	
	Net (Loss) Gain	Prior Service (Cost) Credit	Net (Loss) Gain	Prior Service (Cost) Credit	Net (Loss) Gain	Prior Service (Cost) Credit
	(in millions)					
Balance, December 31, 2008	$ (93)	$ (2)	$ (2)	$ (2)	$ (16)	$ 26
Deferred Benefits	33	(1)			5	3
Amortization	1		1		1	(6)
Total amount recognized in other comprehensive income	34	(1)	1		6	(3)
Balance, December 31, 2009	$ (59)	$ (3)	$ (1)	$ (2)	$ (10)	$ 23
Deferred Benefits			(1)	1	14	(2)
Amortization	1				(1)	(6)
Total amount recognized in other comprehensive loss	1		(1)	1	13	(8)
Balance, December 31, 2010	$ (58)	$ (3)	$ (2)	$ (1)	$ 3	$ 15

During the second quarter of 2010, the Company entered into a new collective bargaining agreement with its Mid-Atlantic employees represented by IBEW Local 1900. The new agreement includes a change to the postretirement healthcare benefit plan covering those union employees to eliminate employer-provided healthcare subsidies through a gradual phase-out. For current employees who retire during the term of this collective bargaining agreement, the gradual phase-out will continue through 2015, at which time those retirees will be responsible for 100% of their healthcare coverage. Subsidies for employees who retired prior to June 1, 2010, continued through December 31, 2010. The curtailment resulted in a remeasurement of the liability related to postretirement benefits for Mid-Atlantic union employees. In performing the remeasurement, the Company used an updated discount rate of 5.31% as compared to the discount rate of 5.62% used in the Company s previous measurement at December 31, 2009, but did not adjust any other valuation assumptions as a result of the remeasurement. The Company recorded the effects of the plan curtailment during the second quarter of 2010 and recognized a reduction in other postretirement liabilities of $48 million and a decrease in accumulated other comprehensive loss of $11 million on the consolidated balance sheet and a gain of $37 million reflected as a reduction in operations and maintenance expense on the consolidated statement of operations. In addition, the Company recognized an increase of $3 million in its pension liability and in accumulated other comprehensive loss as a result of planned salary increases under the new collective bargaining agreement.

During the second quarter of 2008, the Company severed certain employees as a result of the shutdown of the Lovett generating facility. As a result, the Company recognized a curtailment gain of approximately $5 million for its pension and postretirement benefits plans which was reflected as a reduction of operations and maintenance expense.

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of the net periodic benefit cost (credit) of the Company s pension and other postretirement benefit plans for 2010, 2009 and 2008, are:

	Pension Plans			Other Postretirement Benefit Plans		
	2010	2009	2008	2010	2009	2008
	(in millions)					
Service cost	$ 8	$ 8	$ 8	$ 1	$ 2	$ 1
Interest cost	18	16	15	2	3	3
Expected return of plan assets	(23)	(22)	(17)			
Net amortization(1)	1	2	1	(7)	(5)	(5)
Curtailments			(1)	(37)		(4)
Net periodic benefit cost (credit)	$ 4	$ 4	$ 6	$ (41)	$	$ (5)

(1) Net amortization amount includes prior service cost and actuarial gains or losses.

The resulting total amount recognized of (income) loss in net periodic benefit cost and other comprehensive income/loss for the pension plans during 2010 and 2009 was $3 million and $(30) million, respectively. The resulting total amount recognized of (income) loss in net periodic benefit cost and other comprehensive income/loss for the other postretirement benefit plans during 2010 and 2009 was $(46) million and $(3) million, respectively.

The estimated net loss and prior service cost (credit) for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost during 2011 are $(3) million and $(1) million, respectively.

The estimated net loss and prior service cost (credit) for other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost during 2011 are an insignificant amount and $4 million, respectively.

Assumptions

The discount rates used at December 31, 2010 and 2009, were determined based on individual bond-matching models comprised of portfolios of high quality corporate bonds with projected cash flows and maturity dates reflecting the expected time horizon during which that benefit will be paid. Bonds included in the model portfolios are from a cross-section of different issuers, are AA-rated or better, and are non-callable so that the yield to maturity can be attained without intervening calls.

The weighted average assumptions used for measuring year-end pension and other postretirement benefit plan obligations are:

	Pension Plan		Other Postretirement Benefit Plans	
	2010	2009	2010	2009
Discount rate	5.12%	5.62%	4.80%	5.62%
Rate of compensation increase	2.81%	2.99%	3.00%	3.50%

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company assumed healthcare cost trend rates used for measuring year-end other postretirement benefit plan obligations are:

	2010	2009
Assumed medical inflation for next year:		
Before age 65	8.00%	9.00%
Age 65 and after	8.20%	8.50%
Assumed ultimate medical inflation rate	5.50%	5.00%
Year in which ultimate rate is reached	2018	2017

An annual increase or decrease of 1% in the assumed medical care cost trend rate would correspondingly increase or decrease the total accumulated benefit obligation of other postretirement benefit plans at December 31, 2010, by an inconsequential amount.

The weighted average assumptions used for the Company s pension benefit cost and other postretirement benefit costs during each year were as follows:

	Pension Plans			Other Postretirement Benefit Plans		
	2010	2009	2008	2010	2009	2008
Discount rate	5.36%	5.40%	6.12%	5.03%	5.37%	6.06%
Rate of compensation increase	2.98%	3.37%	3.64%	3.23%	3.00%	3.00%
Expected long-term rate of return on plan assets	8.20%	8.50%	8.50%	N/A	N/A	N/A

In determining the long-term rate of return for plan assets, the Company evaluates historic and current market factors such as inflation and interest rates before determining long-term capital market assumptions. The Company also considers the effects of diversification and portfolio rebalancing. To check for reasonableness and appropriateness, the Company reviews data about other companies, including their historic returns.

For purposes of expense recognition, the Company uses a market-related value of assets that recognizes the difference between the expected return and the actual return on plan assets over a five-year period. Unrecognized asset gains or losses associated with its plan assets will be recognized in the calculation of the market-related value of assets and subject to amortization in future periods.

The Company s assumed healthcare cost trend rates used to measure the expected cost of benefits covered by its other postretirement plan are:

	2010	2009	2008

Assumed medical inflation for next year:			
Before age 65	8.40%	8.50%	8.00%
Age 65 and after	8.20%	8.50%	9.50%
Assumed ultimate medical inflation rate	5.30%	5.00%	5.00%
Year in which ultimate rate is reached	2017	2018	2015

An annual increase or decrease of 1% in the assumed medical care cost trend rate would correspondingly increase or decrease the aggregate of the service and interest cost components of the annual other postretirement benefit cost during 2010 by an inconsequential amount.

Pension Plan Assets

Pension plans assets are managed solely in the interest of the plans participants and their beneficiaries and are invested with the objective of earning the necessary returns to meet the time horizons of the accumulated and projected retirement benefit obligations. The Company uses a mix of equities and fixed

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

income investments intended to manage risk to a reasonable and prudent level. The Company s risk tolerance is established through consideration of the plans liabilities and funded status as well as corporate financial condition. Equity investments are diversified across domestic and international stocks. For domestic stocks, the Company employs both a passive and active approach by investing in index funds and an actively managed small cap fund. For international stocks, the Company is invested in both developed and emerging market equity funds. Fixed income investments are substantially comprised of intermediate and long-term United States government and corporate index funds. Derivative securities can be used for diversification, risk-control and return enhancement purposes but may not be used for the purpose of leverage.

The Company is evaluating its pension assets allocation methodology and will make a determination based on the results of a study currently being completed by a third-party investment management firm. The following table shows the target allocations for legacy Mirant and legacy RRI Energy plans and the percentage of fair value of plan assets by asset category (based on the nature of the underlying funds) for the Company s qualified pension plans at December 31, 2010 and 2009:

	Target Allocations		Percentage of Fair Value of Plan Assets at December 31,	
	Mirant	**RRI Energy**	**2010**	**2009**
Domestic stocks	50%	35%	45%	51%
International stocks	20	25	22	20
Global stocks		10	3	
Fixed income securities	30	30	29	28
Cash			1	1
Total	100%	100%	100%	100%

Investment risk and performance are monitored on an ongoing basis through quarterly portfolio reviews of each asset class to a related performance benchmark, if applicable, and annual pension liability measurements. Performance benchmarks are composed of the following indices:

Asset Class	**Index**
Domestic stocks	Dow Jones U.S. Total Stock Market Index
	Russell 1000 Index
	Russell 2000 Index
	S&P 500 Index
	MSCI U.S. Broad Market Index
International stocks	MSCI All Country World Ex-U.S. Index
	Europe, Australia and Far East Index

	MSCI Emerging Markets Index
	FTSE All-World ex-U.S. Index
Global stocks	MSCI All Country World Index
Fixed income securities	Barclays Capital Aggregate Bond Index

Fair Value Hierarchy of Plan Assets

The Company is required to classify the fair value measurements of plan assets according to the fair value hierarchy. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values based on the observability of the inputs used in the valuation techniques for a fair value measurement. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Company s plan assets are classified within Level 1 and Level 2 of the fair value hierarchy.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s plan assets classified within Level 1 consist of exchange-traded investment funds with readily observable prices. The Company s plan assets classified within Level 2 consist of non-exchange-traded investment funds whose fair values reflect the net asset value of the funds based on the fair value of the fund s underlying securities. The underlying securities held by these funds are valued using quoted prices in active markets for identical or similar assets. The Company elected the practical expedient under the accounting guidance to measure the fair value of certain funds that use net asset value per share. Certain investment funds require redemption notification of 30 days or less for which no adjustment was made to their net asset value.

The following table presents plan assets measured at fair value at December 31, 2010, by category (based on the nature of the underlying funds):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
		(in millions)		
Asset Categories:				
Cash and cash equivalents	$ 1	$ 2	$	$ 3
Investment Funds:				
Domestic stocks[(1)]	72	90		162
International stocks[(2)]	60	20		80
Global stocks[(3)]	10			10
Fixed income securities[(4)]	27	77		104
Total	$ 170	$ 189	$	$ 359

(1) Comprised of large-cap stocks (approximately 75%) and small-cap stocks (approximately 25%).

(2) Comprised of large-cap stocks (approximately 75%) and multi-cap stocks (approximately 25%).

(3) Comprised of both foreign and domestic multi-cap stocks.

(4) Comprised primarily of U.S. corporate bonds (approximately 50%) and U.S. government bonds (approximately 45%).

Domestic large-cap stocks holdings represent the largest investment concentration in the plan representing approximately 35% of the plan s assets. There were no other significant concentrations of risk in the plans assets.

The following table presents plan assets measured at fair value at December 31, 2009 by category:

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
		(in millions)		
Asset Categories:				
Cash equivalents	$	$ 3	$	$ 3
Investment Funds:				
Domestic stocks[1]	36	84		120
International stocks[2]	32	17		49
Fixed income securities[3]		68		68
Total	$ 68	$ 172	$	$ 240

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Level 1 stocks are comprised of small-cap growth stocks and Level 2 stocks are comprised of large-cap stocks.

(2) Comprised of large-cap stocks (approximately 65%) and multi-cap stocks (approximately 35%).

(3) Comprised of U.S. government securities (approximately 43%) and corporate bonds (approximately 57%).

The Company expects to contribute approximately $6 million to the tax-qualified pension plans during 2011. In addition, the Company expects to contribute approximately $1 million to the non-tax-qualified pension plans during 2011.

The Company expects the following benefits to be paid from the pension and other postretirement benefit plans:

	Pension Plans		Other Postretirement Benefits Plans	
	Tax-Qualified	Non-Tax Qualified	Before Medicare Subsidy	After Medicare Subsidy
	(in millions)			
2011	$ 17	$ 1	$ 5	$ 5
2012	18	1	6	6
2013	20	1	6	6
2014	21	1	6	6
2015	23	1	6	6
2016 through 2020	150	3	28	27

Employee Savings and Profit Sharing Plan

The Company has employee savings plans under Sections 401(a) and 401(k) of the IRC whereby employees may contribute a portion of their base compensation to the employee savings plan, subject to limits under the IRC. For the periods presented, the Company provided a matching contribution each payroll period equal to 75% of the employee s contributions up to 6% of the employee s pay for that period. As a result of the Merger, the Company changed its contribution levels to provide a matching contribution each payroll period equal to 100% of the employee s contribution up to 6% of the employee s pay for that period. For unionized employees, matching levels vary by bargaining unit.

The Company also provides for a profit sharing arrangement for non-union employees not accruing a benefit under the defined benefit pension plan, whereby the Company contributes a quarterly fixed contribution of 3% of eligible pay and may make an annual discretionary contribution. As a result of the Merger, the Company changed its contribution levels to provide a fixed contribution of 2% of eligible pay per pay period and may make an annual discretionary contribution up to 3% of eligible pay based on the Company s performance. Certain unionized employees are also eligible for the annual discretionary profit sharing contribution.

Expenses recognized for the matching, fixed profit sharing and discretionary profit sharing contributions are:

	Matching	Fixed Profit Sharing	Discretionary Profit Sharing
		(in millions)	
2010	$ 6	$ 2	$ 4
2009	5	2	3
2008	5	2	2

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company also sponsors non-qualified deferred compensation plans for key and highly compensated employees. The Company s obligations under these plans were $37 million and the related rabbi trust investments were $38 million at December 31, 2010.

9. Stock-Based Compensation

Overview. As of the date of the Merger, the GenOn Energy, Inc. 2010 Omnibus Incentive Plan became effective and permits the Company to grant various stock-based compensation awards to employees, consultants and directors. GenOn terminated the RRI Energy, Inc. 2002 Stock Plan, the RRI Energy, Inc. 2002 Long-Term Incentive Plan, the Long-Term Incentive Plan of RRI Energy, Inc., the RRI Energy, Inc. Transition Stock Plan and the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. Outstanding awards under the terminated plans remain subject to the terms and conditions of the applicable plans.

The GenOn Energy, Inc. 2010 Omnibus Incentive Plan provides for the granting of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards, other stock-based awards, covered employee annual incentive awards and non-employee director awards.

At December 31, 2010, 48 million shares are authorized for issuance to participants. Shares covered by an award are counted as used only to the extent that they are actually issued. Any shares related to awards that terminate by expiration, forfeiture, cancellation or otherwise without the issuance of such shares will be available again for grant under the stock-based compensation plan. The Company utilizes both service condition and performance condition forms of stock-based compensation. GenOn has generally issued new shares when stock options are exercised and for other equity-based awards.

Summary. The Company recognizes compensation expense in operations and maintenance expense in the consolidated statements of operations related to stock-based compensation. Compensation expense during 2010, 2009 and 2008 was as follows:

	2010	2009	2008
		(in millions)	
Compensation expense from accelerated vesting of Mirant s stock-based compensation awards upon closing of the Merger	$ 24	$	$
Service condition stock-based compensation expense	16	24	21
Performance condition stock-based compensation expense			5
Modification expense(1)	1		
Total compensation expense (pre-tax)	$ 41	$ 24	$ 26
Income tax effect (includes effect of the valuation allowance)	$	$	$

(1)

Represents modification expense for the vested stock options for Edward R. Muller, Chairman and Chief Executive Officer, which were modified such that the exercise period for the awards coincides with the expiration date.

At December 31, 2010, there was $8 million of total unrecognized compensation cost related to non-vested share-based compensation granted through service condition awards, which is expected to be recognized on a straight-line basis over a weighted average period of approximately two years.

Effects of Merger. Upon completion of the Merger, the following occurred to Mirant s stock-based incentive awards:

- all outstanding Mirant stock options vested, converted into options covering GenOn common stock (with the number of shares subject to such options and the per share exercise price appropriately

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adjusted based on the Exchange Ratio) and remain outstanding, subject to the same terms and conditions as otherwise applied prior to the Merger; and

restricted stock units vested in full, settled in Mirant common stock and converted into GenOn common stock based on the Exchange Ratio (with cash paid in lieu of fractional shares).

As appropriate, all share-based amounts disclosed herein have been adjusted for the Exchange Ratio. The amount of compensation cost recognized immediately upon the close of the Merger in the Company s post-merger consolidated results of operations was $24 million from the accelerated vesting of Mirant s stock options and restricted stock units as a result of the change in control triggered by the Merger.

Upon completion of the Merger, the following occurred to RRI Energy s stock-based incentive awards:

stock options vested in full, converted into options covering GenOn common stock and remain outstanding subject to the same terms and conditions as otherwise applied prior to the Merger;

restricted stock units vested and settled in GenOn common stock; and

cash units vested and settled in cash.

In the purchase price allocation for the Merger (see note 2), RRI Energy s employee stock options and restricted stock units, which vested upon the close of the Merger, were measured and recorded at fair value resulting in an increase in additional paid-in capital of $10 million. In addition, in the purchase price allocation for the Merger, the Company recorded a liability of $6 million for RRI Energy s cash units which vested upon the close of the Merger.

Upon completion of the Merger, Edward R. Muller, Chairman and Chief Executive Officer, was granted an award of restricted stock units with a value equal to two times the sum of his annual base salary and target bonus, which will vest in two equal installments on the first and second anniversaries of completion of the Merger.

In addition, upon completion of the Merger, Mark M. Jacobs, President and Chief Operating Officer, was granted an award of restricted stock units with a value equal to two times his annual base salary and target bonus, which will vest in two equal installments on the first and second anniversaries of completion of the Merger. See note 2 for further information regarding the Merger.

Stock Options

The fair value of stock options is estimated on the grant date using a Black-Scholes option-pricing model based on the assumptions noted in the following table. The Company utilizes its own implied volatility of its traded options in accordance with the accounting guidance related to share-based payments. As a result of the lack of exercise history for Mirant, the simplified method for estimating expected term has been used in accordance with the accounting guidance related to share-based payments. For performance condition awards, the Company utilized the contractual term as the expected term. The risk-free rate for periods within the contractual term of the stock option is based on the United States Treasury yield curve in effect at the time of the grant. The table below includes significant assumptions used in valuing the Company s stock options:

	2010		2009		2008	
	Range	**Weighted Average**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
Expected volatility	39.3%	39.3%	48-59%	58.9%	31-43%	31.2%
Expected dividends	%	%	%	%	%	%
Expected term for service condition awards	6 years	6 years	6 years	6 years	3.5 years	3.5 years
Risk-free rate	3.1%	3.1%	2.6-2.9%	2.6%	2.1-2.9%	2.1%

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Service Condition Awards. The Company grants stock options to certain employees and directors. Historically, stock options vested 33.33% per year for the three years and have a term of five to ten years.

Options to purchase approximately 7.0 million, 3.7 million and 2.3 million shares vested during 2010, 2009 and 2008, respectively, of which approximately 56,397, 706,896 and 105,116 shares for grants made in 2010, 2009 and 2008, respectively, became exercisable as a result of accelerated vesting resulting from the termination of certain employees. The options that vested in 2010 include 5.1 million Mirant stock options which vested upon the closing of the Merger.

Summarized stock options activity is:

	2010			
	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
Stock Options				
Outstanding at January 1	11,454,427	$ 8.48	6.1	$ 6
Granted	2,696,541	$ 4.66		
Assumed in the Merger[(1)]	6,394,871	$ 12.27		
Exercised	(384,381)	$ 3.67		
Forfeited	(146,952)	$ 4.70		
Expired	(2,046,363)	$ 10.30		
Outstanding at December 31	17,968,143	$ 9.19	4.7	$ 1
Exercisable at December 31, 2010	17,968,143	$ 9.19	4.7	$ 1

(1) Upon completion of the Merger, RRI Energy s stock options vested in full, converted into options covering GenOn common stock, and remain outstanding subject to the same terms and conditions as otherwise applied prior to the Merger.

	2010	2009	2008
	(in millions, except per unit amounts)		
Weighted average grant date fair value of the stock options granted	$ 4.66	$ 2.08	$ 3.35
Proceeds from exercise of stock options	1		17

Intrinsic value of exercised stock options			
Tax benefits realized	(1)	(1)	(1)

(1) None realized as a result of the Company s net operating loss carryforwards.

Performance Condition Awards. During 2006, the Company granted stock options to five members of executive management. These options were granted with a three-year term and vested on June 30, 2008, as the Company achieved the required performance target amounts by December 31, 2007. There were no performance condition stock options granted during 2010, 2009 or 2008. At December 31, 2010 and 2009, there were no outstanding performance condition stock options.

Restricted Stock Shares and Restricted Stock Units

Service Condition Awards. The Company historically granted restricted stock units to certain employees and directors. These restricted stock units vested in three equal installments on each of the first, second and third anniversaries of the grant date. In addition, the Company historically granted restricted stock units to

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

non-management members of the Board of Directors. These awards vested one year from the grant date and delivery of the underlying shares was deferred until the directorship terminated.

During 2010, the Company issued 5.2 million restricted stock units. Approximately 7.3 million, 1.5 million and 763,570 restricted stock units vested during 2010, 2009 and 2008, respectively.

The grant date fair value of restricted stock shares and restricted stock units is equal to the Company s closing stock price on the grant date. As restricted stock shares and restricted stock units vest, the outstanding balance of restricted stock shares and restricted stock units decreases and the number of outstanding shares of common stock increases by an equal amount.

Summarized restricted stock shares and restricted stock units activity is:

Restricted Stock Shares and Restricted Stock Units	2010 Number of Shares	2010 Weighted Average Grant Date Fair Value
Outstanding at January 1	4,499,650	$ 5.27
Granted	5,183,669	$ 4.22
Vested	(7,314,604)	$ 5.03
Forfeited	(126,183)	$ 4.56
Outstanding at December 31	2,242,532	$ 3.67
Weighted average period over which the nonvested restricted stock shares and restricted stock units is expected to be recognized	2 years	

	2010	2009	2008
	(in millions, except per unit amounts)		
Weighted average grant date fair value of restricted stock shares and restricted stock units granted	$ 4.22	$ 3.72	$ 13.02
Fair value of vested restricted stock shares and restricted stock units	27	7	20

Performance Condition Awards. During 2006, the Company issued restricted stock units, which vested on June 30, 2008, based on the Company achieving the performance target amounts by December 31, 2007. The grant date fair value of the restricted stock and restricted stock units for performance condition awards is equal to the Company s closing stock price on the grant date. At December 31, 2010 and 2009, there were no outstanding performance condition restricted stock units.

10. Commitments and Contingencies

GenOn has made firm commitments to buy materials and services in connection with its ongoing operations and has provided cash collateral or financial guarantees relative to some of its investments.

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) Commitments.

In addition to debt and other obligations in the consolidated balance sheets, GenOn has the following annual commitments under various agreements at December 31, 2010, related to its operations:

	Off-Balance Sheet Arrangements and Contractual Obligations by Year						
	Total	2011	2012	2013	2014	2015	>5 Years
	(in millions)						
GenOn Mid-Atlantic operating leases	$ 1,730	$ 134	$ 132	$ 138	$ 131	$ 110	$ 1,085
REMA operating leases	882	63	56	64	64	56	579
Other operating leases	227	72	34	25	20	17	59
Fuel commitments	1,343	789	345	209			
Commodity transportation commitments	652	72	80	63	65	66	306
LTSA commitments	441	12	7	11	29	8	374
Maryland Healthy Air Act	155	155					
GenOn Marsh Landing	475	216	239	19	1		
Other	592	365	47	46	39	36	59
Total commitments	$ 6,497	$ 1,878	$ 940	$ 575	$ 349	$ 293	$ 2,462

The Company s contractual obligations table does not include the derivative obligations reported at fair value (other than fuel supply commitments), which are discussed in note 4 and the asset retirement obligations, which are discussed in note 5(d).

GenOn Mid-Atlantic Operating Leases

GenOn Mid-Atlantic leases a 100% interest in both the Dickerson and Morgantown baseload units and associated property through 2029 and 2034, respectively. GenOn Mid-Atlantic has an option to extend the leases. Any extensions of the respective leases would be for less than 75% of the economic useful life of the facility, as measured from the beginning of the original lease term through the end of the proposed remaining lease term. The Company is accounting for these leases as operating leases and recognizes rent expense on a straight-line basis. Rent expense totaled $96 million during 2010, 2009 and 2008, and is included in operations and maintenance expense in the consolidated statements of operations. At December 31, 2010 and 2009, the Company has paid $444 million and $400 million, respectively, of lease payments in excess of rent expense recognized, which is recorded in prepaid rent and prepaid expenses on the consolidated balance sheets. Of these amounts, $96 million is included in prepaid expenses on the Company s consolidated balance sheets at December 31, 2010 and 2009.

At December 31, 2010, the total notional minimum lease payments for the remaining terms of the leases aggregated $1.7 billion and the aggregate termination value for the leases was $1.4 billion, which generally decreases over time. GenOn Mid-Atlantic leases the Dickerson and the Morgantown baseload units from third party owner lessors. These owner lessors each own the undivided interests in these baseload generating facilities. The subsidiaries of the institutional investors who hold the membership interests in the owner lessors are called owner participants. Equity funding by the owner participants plus transaction expenses paid by the owner participants totaled $299 million. The issuance and sale of pass through certificates raised the remaining $1.2 billion needed for the owner lessors to acquire the undivided interests.

The pass through certificates are not direct obligations of GenOn Mid-Atlantic. Each pass through certificate represents a fractional undivided interest in one of three pass through trusts formed pursuant to three separate pass through trust agreements between GenOn Mid-Atlantic and United States Bank National Association (as successor in interest to State Street Bank and Trust Company of Connecticut, National Association), as pass through trustee. The property of the pass through trusts consists of lessor notes. The

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

lessor notes issued by an owner lessor are secured by that owner lessor s undivided interest in the lease facilities and its rights under the related lease and other financing documents. For restrictions under these leases, see note 6.

REMA Operating Leases

REMA leases 16.45% and 16.67% interests in the Conemaugh and Keystone baseload facilities, respectively, through 2034 and expects to make payments through 2029. REMA also leases a 100% interest in the Shawville baseload facility through 2026 and expects to make payments through that date. At the expiration of these leases, there are several renewal options related to fair value. The Company is accounting for these leases as operating leases and recognizes rent expense on a straight-line basis. Rent expense totaled $3 million during December 2010 and is included in operations and maintenance expense in the consolidated statements of operations. The Company operates the Conemaugh and Keystone facilities under five-year agreements that expire in December 2015 that, subject to certain provisions and notifications, could be terminated annually with one year s notice. The Company is reimbursed by the other owners for the cost of direct services provided to the Conemaugh and Keystone facilities. Additionally, the Company received fees of $1 million during December 2010. The fees, which are recorded in operations and maintenance expense in the consolidated statements of operation, are primarily to cover REMA s administrative support costs of providing these services.

At December 31, 2010, the total notional minimum lease payments for the remaining terms of the leases aggregated $882 million and the aggregate termination value for the leases was $752 million, which generally decreases over time. REMA leases the Conemaugh, Keystone and the Shawville facilities from third party owner lessors. These owner lessors each own the undivided interests in these baseload facilities. Equity funding by the owner participants plus transaction expenses paid by the owner participants totaled $169 million. The issuance and sale of pass through certificates raised the remaining $851 million needed for the owner lessors to acquire the undivided interests.

The pass through certificates are not direct obligations of REMA. Each pass through certificate represents a fractional undivided interest in one of the pass through trusts formed pursuant to three separate pass through trust agreements between REMA and Deutsche Bank Trust Company Americas, as pass through trustee. The property of the pass through trusts consists of lessor notes. The lessor notes issued by an owner lessor are secured by that owner lessor s undivided interest in the lease facilities and its rights under the related lease and other financing documents. For restrictions under these leases, see note 6.

Other Operating Leases

GenOn has commitments under other operating leases with various terms and expiration dates. Included in other operating leases is a long-term lease for its corporate headquarters which expires in 2018. Amounts in the table exclude future sublease income of $34 million associated with this long-term lease. Other operating leases also include a tolling agreement on the Vandolah facility which entitles the company to purchase and dispatch electric generating capacity and extends through May 2012. Rent expense totaled $10 million, $9 million and $7 million during 2010, 2009 and 2008, respectively, related to these operating leases.

Fuel and Commodity Transportation Commitments

The Company has commitments under coal agreements and commodity transportation contracts, primarily related to natural gas and coal, of various quantities and durations. At December 31, 2010, the maximum remaining term under any individual fuel supply contract is three years and any transportation contract is 13 years. In addition, for 2012 and 2013, GenOn has committed to purchase volumes of two and one million tons, respectively, under certain coal contracts for which the contract prices are subject to negotiation and agreement prior to the beginning of each year and thus the amounts are not included in the table.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

LTSA Commitments

LTSA commitments primarily relate to long-term service agreements that cover some periodic maintenance, including parts, on power generation turbines. The long-term maintenance agreements terminate from 2014 to 2038 based on turbine usage.

Maryland Healthy Air Act

Maryland Healthy Air Act commitments reflect the remaining expected payments for capital expenditures to comply with the limitations for SO_2, NO_x and mercury emissions under the Maryland Healthy Air Act. The Company completed the installation of the remaining pollution control equipment related to compliance with the Maryland Healthy Air Act in the fourth quarter of 2009. However, provisions in the Company s construction contracts provide that certain payments be made after final completion of the project. See note 18 under Scrubber Contract Litigation for further discussion.

GenOn Marsh Landing

On May 6, 2010, GenOn Marsh Landing entered into an EPC agreement with Kiewit for the construction of the Marsh Landing generating facility. Under the EPC agreement, Kiewit is to design and construct the Marsh Landing generating facility on a turnkey basis, including all engineering, procurement, construction, commissioning, training, start-up and testing. The lump sum cost of the EPC agreement is $499 million (including the $212 million total cost under the Siemens Turbine Generator Supply and Services Agreement which was assigned to Kiewit in connection with the execution of the EPC agreement), plus the reimbursement of California sales and use taxes due under the Siemens Turbine Generator Supply and Services Agreement.

Other

Other primarily represents the open purchase orders less invoices received related to general procurement of products and services purchased in the ordinary course of business. These include construction, maintenance and labor activities at the Company s generating facilities. Other also includes estimated pension and other postretirement benefit funding obligations, deferred compensation plans, liabilities related to accounting for uncertainty in income taxes and miscellaneous noncurrent liabilities.

(b) Cash Collateral.

In order to sell power and purchase fuel in the forward markets and perform other energy trading and marketing activities, the Company often is required to provide trade credit support to its counterparties or make deposits with brokers. In addition, the Company often is required to provide cash collateral for access to the transmission grid to participate in power pools and for other operating activities. In the event of default by the Company, the counterparty can apply cash collateral held to satisfy the existing amounts outstanding under an open contract.

The following is a summary of cash collateral posted with counterparties:

December 31,

	2010	2009
	(in millions)	
Cash collateral posted energy trading and marketing	$ 220	$ 41
Cash collateral posted other operating activities	45	43
Total	$ 265	$ 84

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Guarantees.

GenOn generally conducts its business through various operating subsidiaries which enter into contracts as a routine part of their business activities. In certain instances, the contractual obligations of such subsidiaries are guaranteed by, or otherwise supported by, GenOn or another of its subsidiaries, including by letters of credit issued under the GenOn credit facilities.

In addition, GenOn and its subsidiaries enter into various contracts that include indemnification and guarantee provisions. Examples of these contracts include financing and lease arrangements, purchase and sale agreements, including for commodities, construction agreements and agreements with vendors. Although the primary obligation of GenOn or a subsidiary under such contracts is to pay money or render performance, such contracts may include obligations to indemnify the counterparty for damages arising from the breach thereof and, in certain instances, other existing or potential liabilities. In many cases, the Company s maximum potential liability cannot be estimated because some of the underlying agreements contain no limits on potential liability.

Upon issuance or modification of a guarantee, the Company determines if the obligation is subject to initial recognition and measurement of a liability and/or disclosure of the nature and terms of the guarantee. Generally, guarantees of the performance of a third party are subject to the recognition and measurement, as well as the disclosure provisions, of the accounting guidance related to guarantees. Such guarantees must initially be recorded at fair value, as determined in accordance with the accounting guidance.

Alternatively, guarantees between and on behalf of entities under common control are subject only to the disclosure provisions of the accounting guidance related to guarantors accounting and disclosure requirements for guarantees. The Company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

Letters of Credit and Surety Bonds

At December 31, 2010, GenOn and its subsidiaries were contingently obligated for $267 million under letters of credit issued under the GenOn senior secured revolving credit facility. Most of these letters of credit are issued in support of the obligations of the Company s subsidiaries to perform under commodity agreements, financing or lease agreements or other commercial arrangements. In the event of default by the Company, the counterparty can draw on a letter of credit to satisfy the existing amounts outstanding under an open contract. A majority of these letters of credit expire within one year of issuance, and it is typical for them to be renewed on similar terms. In addition, GenOn Energy Holdings issued $106 million of cash-collateralized letters of credit in support of the GenOn Marsh Landing project. GenOn Marsh Landing also entered into a credit agreement which includes a $50 million senior secured letter of credit facility to support GenOn Marsh Landing s debt service reserve requirements and a $100 million senior secured letter of credit facility to support GenOn Marsh Landing s contractual requirements under its PPA with PG&E, under which no letters of credit were outstanding at December 31, 2010.

At December 31, 2010 and 2009, the Company had obligations outstanding under surety bonds of $50 million and $5 million, respectively, of which $4 million and $4 million, respectively, related to credit support for the transmission upgrades PG&E will be making in order to connect the Marsh Landing generating facility to the power grid.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Following is a summary of letters of credit issued and surety bonds provided:

	December 31, 2010	December 31, 2009
	(in millions)	
Letters of credit rent reserves	$ 133	$ 101
Letters of credit Marsh Landing development project	106	12
Letters of credit energy trading and marketing	96	51
Letters of credit other operating activities	38	47
Surety bonds[1]	50	5
Total	$ 423	$ 216

(1) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations.

Purchase and Sale Guarantees and Indemnifications

In connection with the purchase or sale of an asset or a business by GenOn through a subsidiary, GenOn is typically required to provide certain assurances to the counterparties for the performance of the obligations of such a subsidiary under the purchase or sale agreements. Such assurances may take the form of a guarantee issued by GenOn or a subsidiary on behalf of the obligor subsidiary. The scope of such guarantees would typically include any indemnity obligations owed to such counterparty. Although the terms thereof vary in the scope, exclusions, thresholds and applicable limits, the indemnity obligations of a seller typically include liabilities incurred as a result of a breach of a purchase and sale agreement, including the seller s representations or warranties, unpaid and unreserved tax liabilities and specified retained liabilities, if any. These obligations generally have a term of 12 months from the closing date and are intended to protect the buyer against breaches of the agreement or risks that are difficult to predict or estimate at the time of the transaction. In most cases, the contract limits the liability of the seller. Although the primary indemnity periods under the agreements for the sales of the Philippine and Caribbean businesses and six U.S. natural gas-fired generating facilities have elapsed without any claims being made, the Company continues to have indefinite indemnity obligations in respect of certain representations and covenants that are typically not subject to lapse. No claims have been made in respect thereof and the Company does not expect that it will be required to make any material payments under these guarantee and indemnity provisions.

Commercial Purchase and Sales Arrangements

In connection with the purchase and sale of fuel, emissions allowances and energy to and from third parties with respect to the operation of GenOn s generating facilities, the Company may be required to guarantee a portion of the obligations of certain of its subsidiaries. These obligations may include liquidated damages payments or other unscheduled payments. The majority of the current guarantees are set to expire before the end of 2011, although the obligations of the issuer will remain in effect until all the liabilities created under the guarantee have been satisfied or no longer exist. At December 31, 2010, GenOn and its subsidiaries were contingently obligated for a total of $760 million under such arrangements. The Company does not expect that it will be required to make any material payments under these guarantees.

CenterPoint Guarantees

The Company has guaranteed some non-qualified benefits of CenterPoint s existing retirees at September 20, 2002. The estimated maximum potential amount of future payments under the guarantee is

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$55 million at December 31, 2010 and $4 million is recorded in the consolidated balance sheet for this item, which represents the fair value of the guarantee on the Merger date.

Other Guarantees and Indemnifications

The Company s debt agreements typically indemnify against liabilities that arise from the preparation, entry into, administration or enforcement of the agreement.

GenOn has issued guarantees in conjunction with certain performance agreements and commodity and derivative contracts and other contracts that provide financial assurance to third parties on behalf of a subsidiary or an unconsolidated third party. The guarantees on behalf of subsidiaries are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the relevant subsidiary s intended commercial purposes.

At December 31, 2010, GenOn has issued $158 million of guarantees of obligations that its subsidiaries may incur in connection with construction agreements, equipment leases, interest rate swap agreements, settlement agreements and on-going litigation. The Company does not expect that it will be required to make any material payments under these guarantees.

The Company, through its subsidiaries, participates in several power pools with RTOs. The rules of these RTOs require that each participant indemnify the pool for defaults by other members. Usually, the amount indemnified is based upon the activity of the participant relative to the total activity of the pool and the amount of the default. Consequently, the amount of such indemnification by the Company cannot be quantified.

On a routine basis in the ordinary course of business, GenOn and its subsidiaries indemnify financing parties and consultants or other vendors who provide services to the Company. The Company does not expect that it will be required to make any material payments under these indemnity provisions.

Because some of the guarantees and indemnities GenOn issues to third parties do not limit the amount or duration of its obligations to perform under them, there exists a risk that the Company may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit the Company s liability exposure, the Company may not be able to estimate its potential liability until a claim is made for payment or performance, because of the contingent nature of these contracts.

Except as otherwise noted, GenOn is unable to estimate its maximum potential exposure under these agreements until an event triggering payment occurs. GenOn does not expect to make any material payments under these agreements.

11. Dispositions

As part of the sale of the Philippine business, Mirant retained the rights to future insurance recoveries related to outages of the Sual generating facility that occurred prior to the sale. In the second quarter of 2008, the Company entered into a final settlement and received approximately $50 million in additional insurance recoveries. During 2008, income from discontinued operations includes a gain of $50 million related to this settlement. Of this amount, $41 million related to business interruption recoveries and is included in cost of fuel, electricity and other products and $9 million related to property insurance recoveries and is included in total operating expenses.

12. Earnings Per Share

GenOn calculates basic EPS by dividing income/loss available to stockholders by the weighted average number of common shares outstanding. Diluted EPS gives effect to dilutive potential common shares,

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

including unvested restricted shares and restricted stock units, stock options and warrants. Share amounts below reflect Mirant s historical activity to December 2, 2010 retroactively adjusted to give effect to the Exchange Ratio and include the combined entities for the period from December 3, 2010 through December 31, 2010.

The following table shows the computation of basic and diluted EPS for 2010, 2009 and 2008:

	2010	2009	2008
	(in millions, except per share data)		
Income (loss) from continuing operations	$ (50)	$ 494	$ 1,215
Income from discontinued operations			50
Net income (loss)	$ (50)	$ 494	$ 1,265
Basic and diluted			
Weighted average shares outstanding basic	441	411	527
Shares from assumed exercise of warrants and options	(1)		37
Shares from assumed vesting of restricted stock and restricted stock units	(1)	1	1
Weighted average shares outstanding diluted	441	412	565
Basic EPS			
EPS from continuing operations	$ (0.11)	$ 1.20	$ 2.31
EPS from discontinued operations			0.09
Basic EPS	$ (0.11)	$ 1.20	$ 2.40
Diluted EPS			
EPS from continuing operations	$ (0.11)	$ 1.20	$ 2.15
EPS from discontinued operations			0.09
Diluted EPS	$ (0.11)	$ 1.20	$ 2.24

(1) As the Company incurred a loss from continuing operations for 2010, diluted loss per share is calculated the same as basic loss per share.

For 2010 and 2009, the number of securities that are considered antidilutive increased significantly compared to the same period in 2008, as a result of the decrease in the Company s average stock price. The weighted average number of securities that could potentially dilute basic EPS in the future that were not included in the computation of diluted EPS because to do so would have been antidilutive were as follows:

	2010	2009	2008
		(in millions)	
Series A Warrants[1]	76	76	19
Series B Warrants[1]	20	20	5
Stock options	13	11	5
Restricted stock and restricted stock units	3	2	1
Total number of antidilutive shares	112	109	30

(1) These warrants expired January 3, 2011.

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Stockholders Equity

On December 3, 2010, RRI Energy and Mirant completed the Merger. Upon closing, each issued and outstanding share of Mirant common stock automatically converted into 2.835 shares of common stock of RRI Energy, with cash paid in lieu of fractional shares. See note 2 for further information on the Merger.

The following summary of capital stock activity reflects Mirant s historical activity to December 2, 2010 adjusted to give effect to the Exchange Ratio and includes the combined entities for the period from December 3, 2010 through December 31, 2010.

	Common Stock (shares in millions)
At January 1, 2008	629
Shares repurchased	(246)
Transactions under stock plans	4
Issued for warrants	23
At December 31, 2008	410
Shares repurchased	(1)
Transactions under stock plans	2
Issued for warrants	
At December 31, 2009	411
Shares repurchased	(3)
Transactions under stock plans	8
Issued for warrants	
Issued in connection with the Merger[(1)]	355
At December 31, 2010	771

(1) Represents RRI Energy s outstanding common stock including restricted stock awards which vested upon completion of the Merger.

Stockholders Rights Plan

In November 2010, GenOn amended its stockholder rights plan (Rights Agreement) to help protect the Company s use of its federal NOLs from certain restrictions contained in IRC § 382.

In general and subject to certain exceptions, if a person or group acquires a Beneficial Ownership (as defined in the Rights Agreement) of 4.99% or more of the outstanding common stock of the Company (Acquiring Person), the holder of each preferred stock purchase right (Right) other than Rights beneficially owned by the Acquiring Person, will be entitled to purchase the number of shares of common stock equal to $150 divided by one half of the per share Current Market Price (as defined in the Rights Agreement) of common stock at that time. As an alternative, the board of directors may, at its option, exchange all or part of the Rights for common stock at an exchange ratio of one share of common stock per Right. The amendment to the Rights Agreement exempts persons from being defined as an Acquiring Person that are existing 4.99% stockholders at the time of the amendment or become 4.99% stockholders solely as a result of the Merger. In addition, certain institutional holders are exempt from being defined as an Acquiring Person.

Each share of common stock including newly issued common stock will have one Right attached, which trades with and is inseparable from the common stock. The Rights will expire on the earliest of: (a) November 23, 2013, (b) the time at which the Rights are redeemed or exchanged by the Company, or expire following certain transactions with persons who have acquired the Company s common stock pursuant to a

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GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Permitted Offer (as defined in the Rights Agreement), (c) the adjournment of the 2011 annual meeting of stockholders of the Company, if the stockholders have not approved the Rights Agreement, (d) the repeal of IRC §382 or any successor statute if the board of directors of the Company determines that the Rights Agreement is no longer necessary for the preservation of NOLs or tax benefits and (e) the date on which the board of directors determines that no NOLs or other tax benefits may be carried forward.

Bankruptcy Plan

At December 31, 2010, approximately 1.3 million shares of common stock are, pursuant to the Plan, reserved for unresolved claims. See note 14 for further information on the bankruptcy and note 18 for further information of the Chapter 11 proceedings.

Warrants

Mirant also issued two series of warrants that expired on January 3, 2011. The Series A Warrants and Series B Warrants entitled the holders as of the date of issuance to purchase an aggregate of approximately 35 million and 18 million shares of common stock, respectively. The exercise price of the Series A Warrants and Series B Warrants was $21.87 and $20.54 per share, respectively. In the Merger, all the outstanding Mirant warrants converted into warrants of GenOn entitling the holders to 2.835 shares of GenOn common stock for each warrant. During 2010 and 2009, the warrant exercises were immaterial. During 2008, 8.2 million of Series A Warrants and 10.1 million of Series B Warrants were exercised. Substantially all of these exercises were made by net share settlement, resulting in the issuance of approximately 23 million net shares of common stock during 2008. At December 31, 2010, there were approximately 26.9 million Series A Warrants and 7.1 million Series B Warrants outstanding. The warrants are recorded as a component of additional paid-in capital in the consolidated balance sheets.

GenOn Energy, Inc. 2010 Omnibus Incentive Plan

As of the date of the Merger, the GenOn Energy, Inc. 2010 Omnibus Incentive Plan became effective and permits the Company to grant various stock-based compensation awards to employees, consultants and directors. At December 31, 2010, 48 million shares are authorized for issuance to participants. See note 9 for more detail on the GenOn Energy, Inc. 2010 Omnibus Incentive Plan and effect of the Merger.

Share Repurchases

On November 9, 2007, the Company announced that it planned to return a total of $4.6 billion of excess cash to its stockholders based on four factors: (a) the outlook for the business, (b) preserving the Company s credit profile, (c) maintaining adequate liquidity, including for capital expenditures and (d) maintaining sufficient working capital. Between November 2007 and December 2008, the Company returned $4.1 billion of cash to its stockholders through purchases of 345 million shares of its common stock, including 244 million shares that were purchased through open market purchases in 2008 for $2.7 billion. Pursuant to the Merger Agreement, all of the repurchased shares were retired.

14. Bankruptcy Related Disclosures

Mirant s Plan was confirmed by the Bankruptcy Court on December 9, 2005, and GenOn Energy Holdings emerged from bankruptcy on January 3, 2006. For financial statement presentation purposes, GenOn Energy Holdings recorded the effects of the Plan at December 31, 2005.

GenOn Energy Holdings had no reorganization items, net during 2010, 2009 and 2008.

At December 31, 2010 and 2009, amounts related to allowed claims, estimated unresolved claims and professional fees associated with the bankruptcy that are to be settled in cash were an insignificant amount

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and $3 million, respectively, and these amounts were recorded in accounts payable and accrued liabilities on the consolidated balance sheets. These amounts do not include unresolved claims that will be settled in common stock or the stock portion of claims that are expected to be settled with cash and stock. During 2010, 2009 and 2008, GenOn Energy Holdings paid an insignificant amount, $1 million and $17 million, respectively, in cash related to claims and professional fees from bankruptcy.

15. Variable Interest Entities

MC Asset Recovery

Under the Mirant Plan, the rights to certain actions filed by GenOn Energy Holdings and various of its subsidiaries against third parties were transferred to MC Asset Recovery. Any cash recoveries obtained by MC Asset Recovery from the actions transferred to it, net of fees and costs incurred in prosecuting the actions, are to be paid to the unsecured creditors of Mirant Corporation in the Chapter 11 proceedings and the holders of the equity interests in GenOn Energy Holdings immediately prior to the effective date of the Plan except where such a recovery results in an allowed claim in the bankruptcy proceedings.

MC Asset Recovery, although an indirect wholly-owned subsidiary of GenOn, is governed by managers who are independent of the Company and its other subsidiaries. MC Asset Recovery is considered a VIE because of the Company s potential tax obligations which could arise from potential recoveries from legal actions that MC Asset Recovery is pursuing. Prior to January 1, 2010, under previous accounting guidance, the Company was considered the primary beneficiary of MC Asset Recovery and included the VIE in the Company s consolidated financial statements. Based on the revised guidance related to accounting for VIEs that became effective on January 1, 2010, the Company reassessed its relationship with MC Asset Recovery and determined that the Company is no longer deemed to be the primary beneficiary. The characteristics of a primary beneficiary, as defined in the accounting guidance are: (a) the entity must have the power to direct the activities or make decisions that most significantly affect the VIE s economic performance and (b) the entity must have an obligation to absorb losses or receive benefits that could be significant to the VIE. As MC Asset Recovery is governed by an independent Board of Managers that has sole power and control over the decisions that affect MC Asset Recovery s economic performance, the Company does not meet the characteristics of a primary beneficiary. However, under the Plan, the Company is responsible for the taxes owed, if any, on any net recoveries up to $175 million obtained by MC Asset Recovery. The Company currently retains any tax obligations arising from the next approximately $74 million of potential recoveries by MC Asset Recovery. As a result of the initial application of this accounting guidance, the Company deconsolidated MC Asset Recovery effective January 1, 2010, and adjusted prior periods to conform to the current presentation.

GenOn Energy Holdings was obligated to make contributions to MC Asset Recovery as necessary to pay professional fees and certain other costs reasonably incurred by MC Asset Recovery, including expert witness fees and other costs of the actions transferred to MC Asset Recovery. On March 31, 2009, The Southern Company and MC Asset Recovery entered into a settlement agreement and The Southern Company paid $202 million to MC Asset Recovery. As a result of the settlement and related distributions made in September 2009, GenOn Energy Holdings has no further obligation to provide funding to MC Asset Recovery for professional fees and other costs incurred by MC Asset Recovery. See note 18 for further discussion of MC Asset Recovery.

MC Asset Recovery had current assets and current liabilities, which are not included in the Company s consolidated balance sheets, as follows:

	December 31, 2010	December 31, 2009
	(in millions)	
Current assets	$ 36	$ 39
Current liabilities	(36)	(39)

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

MC Asset Recovery had operations and maintenance expense, which is reflected in equity in income of affiliates in the Company s consolidated statements of operations, as follows:

	2010	2009	2008
		(in millions)	
Operations and maintenance	$	$ 1	$ 16

The net effect of deconsolidation on the consolidated statements of cash flows was as follows:

	2010	2009	2008
		(in millions)	
Cash provided by operating activities	$	$ 5	$ 20
Cash used in investing activities		(5)	(20)

16. Segment Reporting

The Company previously had four reportable segments: Mid-Atlantic, Northeast, California and Other Operations. In the fourth quarter of 2010, in conjunction with the Merger, the Company began reporting in five segments: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. The Company reclassified amounts for 2009 and 2008 to conform to the current segment presentation. The segments were determined based on how the business is managed and aligns with the information provided to the chief operating decision maker for purposes of assessing performance and allocating resources. Generally, the Company s segments are engaged in the sale of electricity, capacity, ancillary and other energy services from their generating facilities in hour-ahead, day-ahead and forward markets in bilateral and ISO markets. The Company also engages in proprietary trading, fuel oil management and natural gas transportation activities. Operating revenues consist of (a) power generation revenues, (b) contracted and capacity revenues, (c) fuel sales and proprietary trading revenues and (d) power hedging revenues.

Upon completion of the Merger, Mirant stockholders had a majority of the voting interest in the combined company. Although RRI Energy issued shares of RRI Energy common stock to Mirant stockholders to effect the Merger, the Merger is accounted for as a reverse acquisition under the acquisition method of accounting. Under the acquisition method of accounting, Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the consolidated financial statements of GenOn include the results of Mirant, from January 1, 2008 through December 2, 2010, and include the results of the combined entities for the period from December 3, 2010 through December 31, 2010, including operating revenues from RRI Energy of $168 million and net loss of $60 million after the Merger.

The Eastern PJM segment consists of eight generating facilities located in Maryland, New Jersey and Virginia with total net generating capacity of 6,336 MW. The Western PJM/MISO segment consists of 23 generating facilities located in Illinois, Ohio and Pennsylvania with total net generating capacity of 7,483 MW. The California segment consists of eight generating facilities located in California, with total net generating capacity of 5,725 MW and includes business development efforts for new generation in California. Energy Marketing includes proprietary trading, fuel oil management and natural gas transportation and storage activities. Other Operations includes nine generating facilities located in Massachusetts, New York, Florida, Mississippi and Texas with total net generating capacity of 5,055 MW. Other Operations also includes unallocated overhead expenses and other activity that can not be specifically identified to another segment. All revenues are generated and long-lived assets are located within the United States.

The Company s measure of profit or loss for its reportable segments is operating income/loss. This measure represents the lowest level of information that is provided to the chief operating decision maker for

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Company s reportable segments. In the following tables, eliminations are primarily related to intercompany sales of emissions allowances.

Operating Segments

	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
			(in millions)				
2010:							
Operating revenues[1]	$ 1,710	$ 118	$ 149	$ 54	$ 239	$	$ 2,270
Cost of fuel, electricity and other products[2]	698	75	23	28	139		963
Gross margin (excluding depreciation and amortization)	1,012	43	126	26	100		1,307
Operating Expenses:							
Operations and maintenance	495	45	78	9	219(3)		846
Depreciation and amortization	142	9	31	1	41		224
Impairment losses[4]	1,153				28	(616)	565
Gain on sales of assets, net	(3)				(1)		(4)
Total operating expenses, net	1,787	54	109	10	287	(616)	1,631
Operating income (loss)	$ (775)	$ (11)	$ 17	$ 16	$ (187)	$ 616	$ (324)
Total assets	$ 4,832	$ 3,846	$ 664	$ 2,771	$ 7,016(5)	$ (3,855)	$ 15,274
Capital expenditures	$ 232	$ 13	$ 40	$	$ 19	$	$ 304

(1) Includes unrealized gains of $80 million for Eastern PJM and unrealized losses of $27 million, $5 million and $3 million for Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized losses of $73 million, $16 million and $3 million for Eastern PJM, Other Operations and Energy Marketing, respectively, and unrealized gains of $5 million for Western PJM/MISO.

(3) Includes $114 million of merger-related costs and $24 million related to the accelerated vesting of Mirant s stock-based compensation as a result of the Merger.

(4) Includes impairment loss of goodwill of $616 million recorded at GenOn Mid-Atlantic on its stand alone balance sheet. The goodwill does not exist at GenOn s consolidated balance sheet. As such, the goodwill impairment loss is eliminated upon consolidation.

(5) Includes the Company s equity method investment in Sabine Cogen, LP of $23 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating Segments

	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
			(in millions)				
2009:							
Operating revenues[1]	$ 1,778	$	$ 154	$ 62	$ 318	$ (3)	$ 2,309
Cost of fuel, electricity and other products[2]	527		32	8	143		710
Gross margin (excluding depreciation and amortization)	1,251		122	54	175	(3)	1,599
Operating Expenses:							
Operations and maintenance	434		78	11	86		609
Depreciation and amortization	98		22	1	28		149
Impairment losses[3]	385		14		5	(183)	221
Gain on sales of assets, net	(14)				(4)	(4)	(22)
Total operating expenses, net	903		114	12	115	(187)	957
Operating income	$ 348	$	$ 8	$ 42	$ 60	$ 184	$ 642
Total assets	$ 5,807	$	$ 144	$ 2,782	$ 2,941	$ (2,146)	$ 9,528
Capital expenditures	$ 578	$	$ 7	$ 2	$ 89	$	$ 676

(1) Includes unrealized gains of $136 million for Eastern PJM and unrealized losses of $113 million and $25 million for Energy Marketing and Other Operations, respectively.

(2) Includes unrealized gains of $8 million and $41 million for Eastern PJM and Other Operations, respectively.

(3) Includes $183 million impairment loss of goodwill recorded at GenOn Mid-Atlantic on its standalone balance sheet. The goodwill does not exist at GenOn s consolidated balance sheet. As such, the goodwill impairment loss is eliminated upon consolidation.

Operating Segments

Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total

	Eastern PJM						
				(in millions)			
2008:							
Operating revenues[1]	$ 2,279	$	$ 186	$ 102	$ 617	$ 4	$ 3,188
Cost of fuel, electricity and other products[2]	565		59	(1)	438	(2)	1,059
Gross margin (excluding depreciation and amortization)	1,714		127	103	179	6	2,129
Operating Expenses:							
Operations and maintenance	412		76	10	169		667
Depreciation and amortization	92		23	1	28		144
Loss (gain) on sales of assets, net	(8)		(7)		(32)	8	(39)
Total operating expenses	496		92	11	165	8	772
Operating income	$ 1,218	$	$ 35	$ 92	$ 14	$ (2)	$ 1,357
Total assets	$ 5,620	$	$ 181	$ 4,717	$ 3,147(3)	$ (2,977)	$ 10,688
Capital expenditures	$ 641	$	$ 6	$ 1	$ 83	$	$ 731

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Includes unrealized gains of $685 million, $120 million and $35 million for Eastern PJM, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized losses of $9 million and $45 million for Eastern PJM and Other Operations, respectively.

(3) Includes the Company s equity method investment in MC Asset Recovery, LLC of $(3) million.

	2010	2009 (in millions)	2008
Operating income (loss) for all segments	$ (324)	$ 642	$ 1,357
Gain on bargain purchase	(518)		
Interest expense	254	138	189
Interest income	(1)	(3)	(70)
Equity in income of affiliates	[1]	1[2]	16[2]
Other, net	(7)		5
Income (loss) from continuing operations before income taxes	$ (52)	$ 506	$ 1,217

(1) Relates to the Company s investment under the equity method in Sabine Cogen, LP which is included in Other Operations.

(2) Relates to the Company s investment under the equity method in MC Asset Recovery which is included in Other Operations.

17. Quarterly Financial Data (Unaudited)

Summarized quarterly financial data for 2010 and 2009 is as follows:

	Quarters Ended March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010[1]
	(in millions except per share data)			
Operating revenues	$ 880[2]	$ 244[3]	$ 775[4]	$ 371[5]
Cost of fuel, electricity and other products	$ 207[2]	$ 272[3]	$ 247[4]	$ 237[5]
Operating income (loss)	$ 458	$ (212)[6]	$ 304	$ (874)
Net income (loss)	$ 407	$ (263)	$ 254	$ (448)[7]
Weighted average shares outstanding basic	412	412	412	525
	$ 0.99	$ (0.64)	$ 0.62	$ (0.85)

Net income (loss) per weighted average shares outstanding basic				
Weighted average shares outstanding diluted	413	412	413	525
Net income (loss) per weighted average shares outstanding diluted	$ 0.99	$ (0.64)	$ 0.62	$ (0.85)

GENON ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Quarters Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
	(in millions except per share data)			
Operating revenues	$ 878(8)	$ 496(9)	$ 454(10)	$ 481(11)
Cost of fuel, electricity and other products	$ 271(8)	$ 150(9)	$ 162(10)	$ 127(11)
Operating income (loss)	$ 424	$ 198(12)	$ 90	$ (70)(13)
Net income (loss)	$ 380	$ 163	$ 55	$ (104)
Weighted average shares outstanding basic	410	411	411	411
Net income (loss) per weighted average shares outstanding basic	$ 0.93	$ 0.40	$ 0.13	(0.25)
Weighted average shares outstanding diluted	410	412	413	411
Net income (loss) per weighted average shares outstanding diluted	$ 0.93	$ 0.40	$ 0.13	$ (0.25)

(1) Includes results from RRI Energy s operations after the Merger. See note 2.

(2) Includes unrealized gains of $363 million in operating revenues and unrealized losses of $11 million in cost of fuel, electricity and other products primarily as a result of decreases in energy prices in the quarter.

(3) Includes unrealized losses of $231 million in operating revenues and unrealized losses of $109 million in cost of fuel, electricity and other products primarily as a result of increases in energy prices and the recognition of many of the coal agreements at fair value in the quarter.

(4) Includes unrealized gains of $154 million in operating revenues and unrealized gains of $13 million in cost of fuel, electricity and other products primarily as a result of decreases in energy prices and increases in coal prices in the quarter.

(5) Includes unrealized losses of $241 million in operating revenues and unrealized gains of $20 million in cost of fuel, electricity and other products primarily as a result of increases in energy prices in the quarter.

(6) Includes $37 million as a result of a curtailment gain resulting from an amendment to the Company s postretirement healthcare benefits plan covering Eastern PJM union employees. See note 8.

(7) Includes impairment losses of $565 million related to the Dickerson and Potomac River generating facilities, $114 million in merger-related costs and $24 million related to the accelerated vesting of Mirant s stock-based compensation as a result of the Merger, offset in part by a gain on bargain purchase of $518 million related to the Merger. See note 2.

(8) Includes unrealized gains of $255 million in operating revenues and unrealized losses of $1 million in cost of fuel, electricity and other products primarily as a result of decreases in energy prices in the quarter.

(9) Includes unrealized losses of $44 million in operating revenues and unrealized gains of $30 million in cost of fuel, electricity and other products primarily as a result of increases in energy prices in the quarter.

(10) Includes unrealized losses of $193 million in operating revenues and unrealized gains of $19 million in cost of fuel, electricity and other products primarily as a result of increases in energy prices in the quarter.

(11) Includes unrealized losses of $20 million in operating revenues and unrealized gains of $1 million in cost of fuel, electricity and other products primarily as a result of increases in energy prices in the quarter.

(12) Includes a reduction in operations and maintenance expense of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, including $52 million for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed and a $10 million reversal of accruals for future funding to MC Asset Recovery.

(13) Includes $207 million in impairment losses related to the Potomac River generating facility.

18. Litigation and Other Contingencies

GenOn is involved in a number of legal proceedings. In certain cases, plaintiffs seek to recover large and sometimes unspecified damages, and some matters may be unresolved for several years. GenOn cannot currently determine the outcome of the proceedings described below or estimate the reasonable amount or range of potential losses, if any, and therefore has not made any provision for such matters unless specifically noted below.

Merger-Related Stockholder Litigation

In April 2010, RRI Energy, Mirant and the members of the Mirant board of directors were named as defendants in four purported class action lawsuits filed in the Superior Court of Fulton County, Georgia, brought in connection with the Merger on behalf of proposed classes consisting of holders of Mirant common stock, excluding the defendants and their affiliates: *Rosenbloom v. Cason, et al.*, No. 2010CV184223, filed April 13, 2010; *The Vladmir Gusinsky Living Trust v. Muller, et al.*, No. 2010CV184331, filed April 15, 2010; *Ng v. Muller, et al.*, No. 2010CV184449, filed April 16, 2010; and *Bayne v. Muller, et al.*, No. 2010CV184648, filed April 21, 2010. The complaints allege, among other things, that the individual defendants breached their fiduciary duties by failing to maximize the value to be received by Mirant s public stockholders and that the other defendants aided and abetted the individual defendants breaches of fiduciary duties. In three of the actions, amended complaints were filed adding allegations that defendants breached their fiduciary duties by failing to disclose certain information in the preliminary joint proxy statement/prospectus related to the Merger. The complaints seek, among other things, rescission of the merger and/or granting the class members any profits or benefits allegedly improperly received by defendants in connection with the Merger.

In August 2010, the court entered an order, consented to by all parties, consolidating the four cases under the caption *In re Mirant Corporation Shareholder Litigation*, No. 2010CV184223, directing that the amended complaint in *Rosenbloom v. Cason, et al.*, No. 2010CV1c824223, serve as the operative complaint, and appointing co-lead counsel. In January 2011, the parties entered into a settlement agreement that, upon final approval by the court, will dismiss the actions. In February 2011, the court preliminarily approved the settlement. The settlement was based on the inclusion of additional disclosures in the Form S-4 filed with the SEC on September 13, 2010. In connection with the settlement, GenOn agreed to pay up to $1.5 million in attorneys fees and expenses to plaintiffs counsel. No further amounts would be payable to the plaintiffs.

Scrubber Contract Litigation

In January 2011, Stone & Webster, Inc., the EPC contractor for the scrubber projects at the Chalk Point, Dickerson and Morgantown facilities, filed two suits against GenOn Mid-Atlantic and one suit against GenOn Chalk Point in the United States District Court for the District of Maryland. Stone & Webster, Inc. claims that it has not been paid in accordance with the terms of the EPC agreements for the scrubber projects and seeks a lien against the properties in the amounts of $43.2 million at Chalk Point, $46.8 million at Dickerson and $29.8 million at Morgantown. GenOn disputes the allegations. The current budget of $1.674 billion continues to represent management s best estimate of the total capital expenditures for compliance with the Maryland Healthy Air Act.

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Pending Natural Gas Litigation

GenOn is party to five lawsuits, several of which are class action lawsuits, in state and federal courts in Kansas, Missouri, Nevada and Wisconsin. These lawsuits relate to alleged conduct to increase natural gas prices in violation of antitrust and similar laws. The lawsuits seek treble or punitive damages, restitution and/or expenses. The lawsuits also name a number of unaffiliated energy companies as parties.

Environmental Matters

Riverkeeper Suit Against GenOn Lovett. In March 2005, Riverkeeper, Inc. filed suit against GenOn Lovett in the United States District Court for the Southern District of New York under the Clean Water Act. The suit alleges that GenOn Lovett failed to implement a marine life exclusion system at its former Lovett facility and to perform monitoring for the exclusion of certain aquatic organisms from the facility s cooling water intake structures in violation of GenOn Lovett s water discharge permit issued by the State of New York. In November 2010, GenOn Lovett and the plaintiff executed a stipulation settling the litigation, which was approved by the court in February 2011. The settlement requires GenOn Lovett to pay the plaintiff $190,000 to fund fish studies or restoration projects in the Hudson River and to reimburse plaintiff for its attorneys fees.

Conemaugh Actions. In April 2007, PennEnvironment and the Sierra Club filed a citizens suit against GenOn in the United States District Court, Western District of Pennsylvania to enforce provisions of the water discharge permit for the Conemaugh plant, of which GenOn is the operator and has a 16.45% interest. PennEnvironment and the Sierra Club seek civil penalties, remediation and an injunction against further violations. GenOn thinks that the Conemaugh plant has operated and will continue to operate in material compliance with its water discharge permit, a consent order agreement with the PADEP, and related state and federal laws. In December 2009, the District Court ordered that the case be dismissed. PennEnvironment and the Sierra Club requested that the court reconsider its ruling. In September 2010, the court ruled that the December 2009 dismissal was erroneous and reinstated the case. This ruling does not change GenOn s general view that it has complied with its permit and consent order agreement with the PADEP. If PennEnvironment and the Sierra Club are ultimately successful, GenOn could incur additional capital expenditures associated with the implementation of discharge reductions and penalties, which it does not think would be material.

Global Warming. In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a suit in the United States District Court for the Northern District of California against GenOn and 23 other electric generating and oil and gas companies. The lawsuit seeks damages of up to $400 million for the cost of relocating the village allegedly because of global warming caused by the greenhouse gas emissions of the defendants. In late 2009, the District Court ordered that the case be dismissed and the plaintiffs appealed. GenOn is also a party to *Comer v. Murphy Oil*, where a group of Mississippi residents and landowners allege the defendants greenhouse gas emissions contributed to the force of Hurricane Katrina. The plaintiffs have not specified the amount of damages they are seeking. In May 2010, the United States Court of Appeals for the Fifth Circuit ordered that the case be dismissed with prejudice. In September 2010, the plaintiffs asked the United States Supreme Court to review that decision. In January 2011, the United States Supreme Court denied the plaintiffs request for review. Although GenOn thinks claims such as these lack legal merit, it is possible that this trend of climate change litigation may continue.

GenOn Potomac River NOVs. In 2010, the Virginia DEQ issued several NOVs to GenOn Potomac River. Virginia DEQ asserted that GenOn Potomac River failed to include required particulate matter data in compliance reports for certain periods in 2009, and that, when the data were later provided, they indicated that particulate matter emissions may have exceeded the permitted limit. GenOn Potomac River thinks that the data indicating exceedance of the limit are erroneous. In another NOV, the Virginia DEQ asserted that on one day in each of February 2010 and July 2010 the opacity readings from the facility exceeded the applicable limits in several six minute intervals. In a third NOV, the Virginia DEQ asserted that GenOn Potomac River

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

combusted used oils in the facility s boilers without authority under its permit and received one shipment of coal that exceeded the maximum ash content allowed under its permit. In a fourth NOV, issued in February 2011, the Virginia DEQ asserted that in January 2011 GenOn Potomac River used a sorbent for the removal of SO_2 that was not permitted. Each of these NOVs states that such violations can result in civil penalties of up to $32,500 per day for each violation.

Montgomery County Carbon Emissions Levy. The Dickerson facility is located in Montgomery County, Maryland, and effective in May 2010, Montgomery County imposed a levy on major emitters of CO_2 in the county of $5 per ton of CO_2 emitted. It is estimated that the CO_2 levy will impose an additional $10 million to $15 million per year in levies owed to Montgomery County. In June 2010, GenOn Mid-Atlantic filed an action against Montgomery County in the United States District Court for the District of Maryland seeking a determination that the CO_2 levy is unlawful. In its complaint, GenOn Mid-Atlantic contends that the CO_2 levy violates its equal protection and due process rights, imposes an unconstitutional excessive fine, is an unconstitutional bill of attainder, constitutes a prohibited special law under the Maryland Constitution, and is preempted by Maryland law and the RGGI, an interstate compact to which Maryland is a party. In July 2010, the district court ruled that the CO_2 levy is a tax rather than a fee and granted a motion filed by Montgomery County seeking dismissal of the suit under the federal Tax Injunction Act for lack of jurisdiction. GenOn Mid-Atlantic has appealed that ruling to the United States Court of Appeals for the Fourth Circuit.

New Source Review Matters. The EPA and various states are investigating compliance of coal-fueled electric generating facilities with the pre-construction permitting requirements of the Clean Air Act known as new source review. In the past decade, the EPA has made information requests concerning the Avon Lake, Chalk Point, Cheswick, Conemaugh, Dickerson, Elrama, Keystone, Morgantown, New Castle, Niles, Portland, Potomac River, Shawville and Titus generating facilities. GenOn is corresponding or has corresponded with the EPA regarding all of these requests. The EPA agreed to share information relating to its investigations with state environmental agencies. In January 2009, GenOn received an NOV from the EPA alleging that past work at its Shawville, Portland and Keystone generating facilities violated the agency s regulations regarding new source review.

In December 2007, the New Jersey Department of Environmental Protection filed suit against GenOn in the United States District Court in Pennsylvania, alleging that new source review violations occurred at the Portland generating facility. The suit seeks installation of best available control technologies for each pollutant, to enjoin GenOn from operating the generating facility if it is not in compliance with the Clean Air Act and civil penalties. The suit also names three past owners of the plant as defendants. In March 2009, the Connecticut Department of Environmental Protection became an intervening party to the suit.

GenOn thinks that the work listed by the EPA and the work subject to the New Jersey Department of Environmental Protection suit were conducted in compliance with applicable regulations. However, any final finding that GenOn violated the new source review requirements could result in fines, penalties or significant capital expenditures associated with the implementation of emissions reductions on an accelerated basis. Most of these work projects were undertaken before GenOn s ownership or lease of those facilities. GenOn thinks that it is indemnified by or has the right to seek indemnification from the prior owners for certain losses and expenses that it may incur from activities occurring prior to its ownership.

Brandywine Fly Ash Facility. In April 2010, the MDE filed a complaint against GenOn Mid-Atlantic and GenOn MD Ash Management in the United States District Court for the District of Maryland asserting violations of the Clean Water Act and Maryland s Water Pollution Control Law. The MDE contends that the operation of the Brandywine fly ash facility has resulted in discharges of pollutants that violate Maryland s water quality criteria. The complaint requests that the court, among other things, (a) enjoin further disposal of coal combustion waste at the Brandywine facility, (b) require the defendants to close and cap the existing open disposal cells within one year, (c) impose civil penalties of up to $37,500 per day per violation and (d) award

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them attorney s fees. GenOn MD Ash Management and GenOn Mid-Atlantic dispute the allegations. In September 2010, four environmental advocacy groups became intervening parties in the proceeding.

Faulkner Fly Ash Facility. In May 2008, the MDE filed a complaint against GenOn Mid-Atlantic and GenOn MD Ash Management in the Circuit Court for Charles County, Maryland alleging violations of Maryland s water pollution laws. The MDE contends that the operation of the Faulkner fly ash facility has resulted in the discharge of pollutants that exceed Maryland s water quality criteria and without the appropriate NPDES permit. The MDE also alleges that the defendants failed to perform certain sampling and reporting required under an applicable NPDES permit. The MDE complaint requests that the court (a) prohibit continuation of the alleged unpermitted discharges, (b) require the defendants to cease from further disposal of any coal combustion byproducts at the Faulkner facility and close and cap the existing disposal cells and (c) assess civil penalties of up to $10,000 per day per violation. In July 2008, GenOn MD Ash Management and GenOn Mid-Atlantic filed a motion to dismiss the complaint, arguing that the discharges are permitted by a December 2000 Consent Order. In January 2011, MDE sought to dismiss without prejudice its complaint. MDE also informed GenOn that it intends to file a similar lawsuit in federal court.

Westland Fly Ash Facility. In January 2011, MDE informed GenOn that MDE intends to file a complaint related to alleged violations of Maryland s water pollution laws at GenOn s Westland fly ash facility located in Montgomery County, Maryland.

Ash Disposal Facility Closures. GenOn is responsible for environmental costs related to the future closures of several ash disposal facilities. GenOn recorded the estimated discounted costs ($36 million and $9 million at December 31, 2010 and 2009, respectively) associated with these environmental liabilities as part of its asset retirement obligations. See note 5(d).

Remediation Obligations. GenOn is responsible for environmental costs related to site contamination investigations and remediation requirements at four generating facilities in New Jersey. GenOn recorded the estimated long-term liability for the remediation costs of $7 million at December 31, 2010.

Chapter 11 Proceedings

In July 2003, and various dates thereafter, GenOn Energy Holdings and certain of its subsidiaries (collectively, the Mirant Debtors) filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court. GenOn Energy Holdings and most of the other Mirant Debtors emerged from bankruptcy on January 3, 2006, when the Plan became effective. The remaining Mirant Debtors emerged from bankruptcy on various dates in 2007. Approximately 461,000 of the shares of GenOn Energy Holdings common stock to be distributed under the Plan have not yet been distributed and have been reserved for distribution with respect to claims disputed by the Mirant Debtors that have not been resolved. Upon the Merger, those reserved shares converted into a reserve for approximately 1.3 million shares of GenOn common stock. Under the terms of the Plan, upon the resolution of such a disputed claim, the claimant will receive the same pro rata distributions of common stock, cash, or both as previously allowed claims, regardless of the price at which the common stock is trading at the time the claim is resolved. If the aggregate amount of any such payouts results in the number of reserved shares being insufficient, additional shares of common stock may be issued to address the shortfall.

Actions Pursued by MC Asset Recovery

Under the Plan, the rights to certain actions filed by GenOn Energy Holdings and various of its subsidiaries against third parties were transferred to MC Asset Recovery, a wholly-owned subsidiary of GenOn Energy Holdings. MC Asset Recovery is governed by managers who are independent of GenOn and its other subsidiaries. Under the Plan, any cash recoveries obtained by MC Asset Recovery from the actions transferred to it, net of fees and costs incurred in prosecuting the actions, are to be paid to the unsecured creditors of GenOn Energy Holdings in the Chapter 11 proceedings and the holders of the equity interests in GenOn

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Energy Holdings immediately prior to the effective date of the Plan except where such a recovery results in an allowed claim in the bankruptcy proceedings, as described below. MC Asset Recovery is a disregarded entity for income tax purposes, and GenOn Energy Holdings is responsible for income taxes related to its operations. The Plan provides that Mirant may not reduce payments to be made to unsecured creditors and former holders of equity interests from recoveries obtained by MC Asset Recovery for the taxes owed by GenOn Energy Holdings, if any, on any net recoveries up to $175 million. If the aggregate recoveries exceed $175 million net of costs, then GenOn Energy Holdings may reduce the payments by the amount of any taxes it will owe or NOLs utilized with respect to taxable income resulting from the amount in excess of $175 million.

The Plan and the MC Asset Recovery Limited Liability Company Agreement also obligate GenOn Energy Holdings to make contributions to MC Asset Recovery as necessary to pay professional fees and certain other costs. In June 2008, GenOn Energy Holdings and MC Asset Recovery, with the approval of the Bankruptcy Court, agreed to limit the total amount of funding to be provided by GenOn Energy Holdings to MC Asset Recovery to $68 million, and the amount of such funding obligation not already incurred by GenOn Energy Holdings at that time was fully accrued. GenOn Energy Holdings was entitled to be repaid the amounts it funded from any recoveries obtained by MC Asset Recovery before any distribution was made from such recoveries to the unsecured creditors of GenOn Energy Holdings and the former holders of equity interests.

In March 2009, The Southern Company (Southern Company) and MC Asset Recovery entered into a settlement agreement resolving claims asserted by MC Asset Recovery in a suit that was pending in the Northern District of Georgia (the Southern Company Litigation). Southern Company paid $202 million to MC Asset Recovery in settlement of all claims asserted in the Southern Company Litigation. MC Asset Recovery used a portion of that payment to pay fees owed to the managers of MC Asset Recovery and other expenses of MC Asset Recovery not previously funded by GenOn Energy Holdings, and it retained $47 million from that payment to fund future expenses and to apply against unpaid expenditures. MC Asset Recovery distributed the remaining $155 million to GenOn Energy Holdings. In accordance with the Plan, GenOn Energy Holdings retained approximately $52 million of that distribution as reimbursement for the funds it had provided to MC Asset Recovery and costs it incurred related to MC Asset Recovery that had not been previously reimbursed. GenOn recognized the $52 million as a reduction of operations and maintenance expense for the year ended December 31, 2009. Pursuant to MC Asset Recovery s Limited Liability Company Agreement and an order of the Bankruptcy Court dated October 31, 2006, GenOn Energy Holdings distributed $2 million to the managers of MC Asset Recovery. In September 2009, the remaining approximately $101 million of the amount recovered by MC Asset Recovery was distributed pursuant to the terms of the Plan. Following these distributions, GenOn Energy Holdings has no further obligation to provide funding to MC Asset Recovery. As a result, GenOn Energy Holdings reversed its remaining accrual of $10 million of funding obligations as a reduction in operations and maintenance expense for 2009. GenOn does not expect to owe any taxes related to the MC Asset Recovery settlement with Southern Company.

One of the two remaining actions transferred to MC Asset Recovery seeks to recover damages from Commerzbank AG and various other banks (the Commerzbank Defendants) for alleged fraudulent transfers that occurred prior to the filing of GenOn Energy Holdings bankruptcy proceedings. In its amended complaint, MC Asset Recovery alleges that the Commerzbank Defendants in 2002 and 2003 received payments totaling approximately 153 million Euros directly or indirectly from GenOn Energy Holdings under a guarantee provided by GenOn Energy Holdings in 2001 of certain equipment purchase obligations. MC Asset Recovery alleges that at the time GenOn Energy Holdings provided the guarantee and made the payments to the Commerzbank Defendants, GenOn Energy Holdings was insolvent and did not receive fair value for those transactions. In December 2010, the United States District Court for the Northern

District of Texas dismissed MC Asset Recovery s complaint against the Commerzbank Defendants. In January 2011, MC Asset Recovery appealed the United States District Court s dismissal of its complaint against the Commerzbank Defendants to the United States Court of Appeals for the Fifth Circuit. If MC Asset Recovery succeeds in obtaining any recoveries on these avoidance claims, the Commerzbank Defendants have asserted that they will seek to file claims in

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GenOn Energy Holdings bankruptcy proceedings for the amount of those recoveries. GenOn Energy Holdings would vigorously contest the allowance of any such claims on the ground that, among other things, the recovery of such amounts by MC Asset Recovery does not reinstate any enforceable pre-petition obligation that could give rise to a claim. If such a claim were to be allowed by the Bankruptcy Court as a result of a recovery by MC Asset Recovery, then the Plan provides that the Commerzbank Defendants are entitled to the same distributions as previously made under the Plan to holders of similar allowed claims. Holders of previously allowed claims similar in nature to the claims that the Commerzbank Defendants would seek to assert have received 43.87 shares of GenOn Energy Holdings common stock for each $1,000 of claim allowed by the Bankruptcy Court. If the Commerzbank Defendants were to receive an allowed claim as a result of a recovery by MC Asset Recovery on its claims against them, the order entered by the Bankruptcy Court on December 9, 2005, confirming the Plan provides that GenOn Energy Holdings would retain from the net amount recovered by MC Asset Recovery an amount equal to the dollar amount of the resulting allowed claim rather than distribute such amount to the unsecured creditors and former equity holders as described above.

Complaint Challenging Capacity Rates Under the RPM Provisions of PJM s Tariff

In May 2008, several parties, including the state public utility commissions of Maryland, Pennsylvania, New Jersey and Delaware, ratepayer advocates, certain electric cooperatives, various groups representing industrial electricity users, and federal agencies (the RPM Buyers), filed a complaint with the FERC asserting that capacity auctions held to determine capacity payments under the RPM provisions of PJM s tariff had produced rates that were unjust and unreasonable. PJM conducted the capacity auctions that are the subject of the complaint to set the capacity payments in effect under the RPM provisions of its tariff for twelve month periods beginning June 1, 2008, June 1, 2009, and June 1, 2010. The RPM Buyers allege that (a) the times between when the auctions were held and the periods that the resulting capacity rates would be in effect were too short to allow competition from new resources in the auctions, (b) the administrative process established under the RPM provisions of PJM s tariff was inadequate to restrain the exercise of market power by the withholding of capacity to increase prices, and (c) the locational pricing established under the RPM provisions of PJM s tariff created opportunities for sellers to raise prices while serving no legitimate function. The RPM Buyers asked the FERC to reduce significantly the capacity rates established by the capacity auctions and to set June 1, 2008, as the date beginning on which any rates found by the FERC to be excessive would be subject to refund. If the FERC were to reduce the capacity payments set through the capacity auctions to the rates proposed by the RPM Buyers, the capacity revenue GenOn has received or expects to receive for the period June 1, 2008 through May 31, 2011, would be reduced by approximately $796 million. In September 2008, the FERC issued an order dismissing the complaint. The FERC found that no party had violated the RPM provisions of PJM s tariff and that the prices determined during the auctions were in accordance with the tariff s provisions. The RPM Buyers filed a request for rehearing, which the FERC denied in June 2009. Certain of the RPM Buyers have appealed the orders entered by the FERC to the United States Court of Appeals for the Fourth Circuit. That appeal was transferred to the United States Court of Appeal for the District of Columbia Circuit. On February 8, 2011, the D.C. Circuit affirmed the FERC rulings.

Excess Mitigation Credits

To facilitate the transition to competition in Texas, the Public Utility Commission of Texas (PUCT) imposed excess mitigation credits (EMCs) on CenterPoint that had the effect of lowering monthly charges payable to CenterPoint by retail energy providers. Prior to the sale of its retail business in 2009, GenOn was a retail energy provider. CenterPoint sought recovery of EMCs that it credited to all retail energy providers, including GenOn, and in December 2004 the

PUCT ordered that relief. CenterPoint represents that EMCs credited to GenOn totaled $385 million. On appeal, the Texas Third Circuit Court of Appeals ruled that CenterPoint s recovery should exclude EMCs credited to GenOn for GenOn s price-to-beat customers, which CenterPoint represents totaled $385 million. The case is now pending before the Texas Supreme Court. CenterPoint has indicated that

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in the event it is unable to recover the EMC credits applied to GenOn through CenterPoint s rates, it may assert a claim against GenOn for such credits. If CenterPoint were to seek recovery of EMCs directly from GenOn, GenOn has agreed to suspend unexpired deadlines on contractual limitation periods that may apply to such a claim. The Company thinks that any such claim by CenterPoint lacks legal merit.

CenterPoint Indemnity

GenOn has agreed to indemnify CenterPoint against certain losses relating to the lawsuits described in this note under Pending Natural Gas Litigation.

Texas Franchise Audit

In 2008 and 2009, the state of Texas, as a result of its audit, issued franchise tax assessments against the Company indicating an underpayment of franchise tax of approximately $68 million (including interest and penalties through December 31, 2010 of $25 million). These assessments are related primarily to a claim by Texas that would change the sourcing of intercompany receipts for the years 2000 through 2006, thereby increasing the amount of tax due to Texas. The Company disagrees with most of the State s assessment and its determination of the related tax liability. Given the disagreement with the State s position, the Company has recognized a portion of the liability but has protested the entire assessment and is currently in the administrative appeals process. If the Company does not fully resolve or come to satisfactory settlement of the protested issues, then it could pay up to the entire amount of the assessed tax, penalties and interest. The Company intends to defend fully its position in the administrative appeals process and if such defense requires litigation, would be required to pay the full assessment and sue for refund.

19. Settlements and Other Charges

Potomac River Settlement

In July 2008, the City of Alexandria, Virginia (in which the Potomac River generating facility is located) and GenOn Potomac River entered into an agreement pursuant to which GenOn Potomac River committed to spend $34 million over several years to reduce particulate emissions. The $34 million was placed in escrow and included in funds on deposit and other noncurrent assets in the consolidated balance sheets. At December 31, 2010, the balance in the escrow account was $32 million.

GenOn Potrero Settlement with City of San Francisco

GenOn Potrero and the City and County of San Francisco, California entered into a settlement agreement (the Potrero Settlement) that became effective in November 2009 upon its approval by the City s Board of Supervisors and Mayor. Among other things, the Potrero Settlement obligates GenOn Potrero to close permanently each of the remaining units of the Potrero generating facility at the end of the year in which the CAISO determines that such unit is no longer needed to maintain the reliable operation of the electricity system. The agreement also bars GenOn Potrero from building any additional generating facilities on the site of the Potrero generating facility. In September 2010, the CAISO notified GenOn Potrero that it was designating all four units of the Potrero generating facility as needed for reliability purposes in 2011. The subsequent completion of the TransBay Cable project, an underwater electric transmission cable that became fully operational in November 2010, eliminated the need for unit 3 of the Potrero generating facility for reliability purposes. The replacement in late 2010 of two underground transmission cables eliminated the need for units 4, 5 and 6 for reliability purposes. In December 2010, the CAISO provided GenOn Potrero with the requisite notice of termination of the RMR agreement. On January 19, 2011, at the request of GenOn Potrero, the FERC approved changes to GenOn Potrero s RMR agreement to allow the CAISO to terminate the RMR agreement effective February 28, 2011. On February 28, 2011, the Potrero facility was shut down.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
GenOn Energy, Inc.:

We have audited and reported separately herein on the consolidated financial statements of GenOn Energy, Inc. and subsidiaries (the Company) at December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders equity and comprehensive income (loss) and cash flows for each of the years in the three-year period ended December 31, 2010. In connection with our audits of the aforementioned consolidated financial statements, we also audited the related financial statement schedules as listed within Item 15. These financial statement schedules are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statement schedules based on our audits.

In our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Houston, Texas
March 1, 2011

Schedule I

GENON ENERGY, INC. (PARENT)

CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF OPERATIONS

	2010	2009	2008
		(in millions)	
Operating income	$	$ 63	$ 18
Other (Income) Expense, net:			
Equity (earnings) losses of subsidiaries (includes gain on bargain purchase of $518 million)	43	(437)	(1,161)
Interest income nonaffiliate		(2)	(53)
Interest income affiliate	(12)		(1)
Interest expense nonaffiliate	21		
Other, net		(1)	
Total other (income) expense, net	52	(440)	(1,215)
Income (loss) from continuing operations before income taxes	(52)	503	1,233
Provision (benefit) for income taxes	(2)	9	3
Income (loss) from continuing operations	(50)	494	1,230
Income from discontinued operations, net			35
Net income (loss)	$ (50)	$ 494	$ 1,265

The accompanying notes are an integral part of the registrant s condensed financial information

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Schedule I

GENON ENERGY, INC. (PARENT)

CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 577	$ 1,523
Funds on deposit	319	
Receivables, net	6	
Receivable from affiliates, net	106	
Notes receivables affiliate	3,238	16
Total current assets	4,246	1,539
Noncurrent Assets:		
Investments in affiliates	3,125	2,747
Notes receivables affiliate	1,003	
Other	106	36
Total noncurrent assets	4,234	2,783
Total Assets	$ 8,480	$ 4,322
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 279	$
Accounts payable and accrued liabilities	37	1
Payable to affiliates		6
Taxes payable	28	
Other	33	
Total current liabilities	377	7
Noncurrent Liabilities:		
Long term debt, net of current portion	2,473	
Total noncurrent liabilities	2,473	
Commitments and Contingencies		
Stockholders Equity:		

Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at December 31, 2010 and 2009		
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 770,857,530 shares and 410,924,221 shares at December 31, 2010 and 2009, respectively	1	
Additional paid-in capital	7,432	6,096
Accumulated deficit	(1,778)	(1,728)
Accumulated other comprehensive loss	(25)	(53)
Total stockholders equity	5,630	4,315
Total Liabilities and Stockholders Equity	$ 8,480	$ 4,322

The accompanying notes are an integral part of the registrant s condensed financial information

Schedule I

GENON ENERGY, INC. (PARENT)

CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS

	2010	2009 (in millions)	2008
Cash Flows from Operating Activities:			
Net cash provided by (used in) operating activities	$ (39)	$ 165	$ 357
Cash Flows from Investing Activities:			
Cash acquired from RRI Energy, Inc.	689		
Issuance of notes receivables affiliate	(1,049)	(94)	(53)
Cash retained by GenOn Energy Holdings	(1,432)		
Capital contributions to subsidiaries		(4)	(304)
Restricted cash	(286)		
Net cash used in investing activities	(2,078)	(98)	(357)
Cash Flows from Financing Activities:			
Proceeds from issuance of long-term debt	1,203		
Debt issuance costs	(25)		
Share repurchases	(11)	(4)	(2,761)
Issuance (repayment) of debt affiliate	3	(1)	(27)
Proceeds from exercises of stock options and warrants	1		18
Net cash provided by (used in) financing activities	1,171	(5)	(2,770)
Net Increase (Decrease) in Cash and Cash Equivalents	(946)	62	(2,770)
Cash and Cash Equivalents, beginning of year	1,523	1,461	4,231
Cash and Cash Equivalents, end of year	$ 577	$ 1,523	$ 1,461
Supplemental Disclosures:			
Cash paid for interest, net of amounts capitalized	$ 60	$	$
Cash paid for income taxes (net of refunds received)	$ (1)	$ 6	$
Supplemental Disclosures for Non-Cash Investing and Financing Activities:			
Conversion to equity of notes receivables from subsidiaries	$ (87)	$ (159)	$ (13)
Conversion to equity of notes payable to subsidiaries	$ 3	$	$ 93

The accompanying notes are an integral part of the registrant s condensed financial information

Schedule I

GENON ENERGY, INC. (PARENT)

NOTES TO REGISTRANTS CONDENSED FINANCIAL STATEMENTS

1. Background and Basis of Presentation

Background

The condensed parent company financial statements have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X, as the restricted net assets of GenOn Energy Inc. s subsidiaries exceed 25 percent of the consolidated net assets of GenOn Energy, Inc. These statements should be read in conjunction with the consolidated statements and notes thereto of GenOn Energy, Inc.

GenOn, a Delaware corporation, was formed in August 2000 by CenterPoint (then known as Reliant Energy, Incorporated) in connection with the planned separation of its regulated and unregulated operations. CenterPoint transferred substantially all of its unregulated businesses, including the name Reliant Energy, to the company now named GenOn Energy, Inc. In May 2001, Reliant Energy (then known as Reliant Resources, Inc.) became a publicly traded company and in September 2002, CenterPoint distributed its remaining ownership of Reliant Energy s common stock to its stockholders. RRI Energy changed its name from Reliant Energy, Inc. effective May 2, 2009 in connection with the sale of its retail business. GenOn changed its name from RRI Energy, Inc. effective December 3, 2010. The Company refers to GenOn Energy, Inc. and, except where the context indicates otherwise, its subsidiaries, after giving effect to the Merger.

Merger of Mirant and RRI Energy

On December 3, 2010, Mirant and RRI Energy completed the Merger contemplated by the Merger Agreement. Upon completion of the Merger, RRI Energy Holdings, Inc. (Merger Sub), a direct and wholly-owned subsidiary of RRI Energy merged with and into Mirant, with Mirant continuing as the surviving corporation and a wholly-owned subsidiary of RRI Energy. Each of Mirant and RRI Energy received legal opinions that the Merger qualified as a tax-free reorganization under the IRC. Accordingly, none of RRI Energy, Merger Sub, Mirant or any of the Mirant stockholders will recognize any gain or loss in the transaction, except that Mirant stockholders will recognize a gain or loss with respect to cash received in lieu of fractional shares of RRI Energy common stock. Upon the closing of the Merger, each issued and outstanding share of Mirant common stock, including grants of restricted common stock, automatically converted into 2.835 shares of common stock of RRI Energy based on the Exchange Ratio. Additionally, upon the closing of the Merger, RRI Energy was renamed GenOn. Mirant stock options and other equity awards converted upon completion of the Merger into stock options and equity awards with respect to GenOn common stock, after giving effect to the Exchange Ratio. At the close of the Merger, former Mirant stockholders owned approximately 54% of the equity of the combined company and former RRI Energy stockholders owned approximately 46% of the equity of the combined company. See note 2 for additional information on the Merger and note 6 for the related debt transactions, each in the consolidated financial statements of GenOn.

Basis of Presentation

Upon completion of the Merger, Mirant stockholders had a majority of the voting interest in the combined company. Although RRI Energy issued shares of RRI Energy common stock to Mirant stockholders to effect the Merger, the Merger is accounted for as a reverse acquisition under the acquisition method of accounting. Under the acquisition method of accounting, Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the condensed financial statements of GenOn Energy, Inc. (parent) include the results of GenOn Energy Holdings (former parent) from January 1, 2008 through December 2, 2010 and include the results of GenOn Energy, Inc. for the period from December 3, 2010 through December 31, 2010. The condensed financial statements presented herein for periods ended prior to the closing of the Merger (and any other financial information presented herein with

GENON ENERGY, INC. (PARENT)

NOTES TO REGISTRANTS CONDENSED FINANCIAL STATEMENTS (Continued)

respect to such pre-merger dates, unless otherwise specified) are the condensed financial statements and other financial information of Mirant.

Equity earnings of subsidiaries consists of earnings of direct subsidiaries of GenOn Energy, Inc. (parent), which includes earnings of subsidiaries whose operations were classified as discontinued operations in the consolidated financial statements of GenOn Energy, Inc.

Income from discontinued operations, net includes discontinued operations activity for only GenOn Energy, Inc. (parent), which is primarily related to deferred taxes stemming from discontinued operations and parent level consolidation entries related to intercompany transactions.

The condensed statement of cash flows for 2008 has been revised to reflect the reclassification of capital contributions to subsidiaries from financing activities to investing activities. The amount revised was $304 million for 2008. The effect of this revision was not considered to be material to the previously issued financial statements. The reclassification had no effect on the GenOn Energy, Inc. s cash and cash equivalents, net income or stockholders equity.

In addition, certain prior period amounts have been reclassified to conform to the current period financial statement presentation.

During 2010, 2009 and 2008, GenOn Energy, Inc. received cash dividends from its subsidiaries of $112 million, $115 million and $297 million, respectively.

2. Long-Term Debt

For a discussion of GenOn Energy, Inc. s long-term debt, see note 6 to GenOn s consolidated financial statements.

Debt maturities of GenOn Energy, Inc. at December 31, 2010 are (in millions):

2011	$	279(1)
2012		
2013		
2014		575
2015		
2016 and thereafter		1,950
Total	$	2,804

(1) Represents GenOn Energy, Inc. senior secured notes redeemed on January 3, 2011.

3. Commitments and Contingencies

At December 31, 2010, the parent company had $918 million of guarantees, which are included in note 10(c) to GenOn s consolidated financial statements.

See notes 10 and 18 to GenOn s consolidated financial statements for a detailed discussion of GenOn Energy, Inc. s contingencies.

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Schedule II

GENON ENERGY, INC. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

	December 31, 2010, 2009 and 2008				
		Additions			
Description	**Balance at Beginning of Period**	**Charged to Income**	**Charged to Other Accounts**	**Deductions[(1)]**	**Balance at End of Period**
	(in millions)				
Provision for uncollectible accounts (current)					
2010	$ 4	$ 8	$	$ (5)	$ 7
2009	13	9		(18)	4
2008	12	3	2	(4)	13
Provision for uncollectible accounts (noncurrent)					
2010	$ 11	$ 18	$	$ (14)	$ 15
2009	42	13		(44)	11
2008	6	41	(2)	(3)	42

(1) Deductions in 2010 and 2009 consisted primarily of reversals of credit reserves for derivative contract assets. Deductions in 2008 consisted primarily of reductions in or write-offs of allowances for uncollectible accounts and notes receivable.

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3. Exhibit Index

Exhibit No.	Exhibit Name
2.1	Agreement and Plan of Merger by and among RRI Energy, Inc., RRI Energy Holdings, Inc. and Mirant Corporation, dated at April 11, 2010 (Incorporated herein by reference to Exhibit 2.1 to the Registrant s Current Report on Form 8-K filed April 12, 2010)
2.2	Letter Agreement dated at April 30, 2009 re: Effectiveness of the Closing of the Membership Interest Purchase Agreement by and between Reliant Energy, Inc. and NRG Retail LLC, dated at February 28, 2009 (Incorporated herein by reference to Exhibit 2.4 to the Registrant s Quarterly Report on Form 10-Q filed May 11, 2009)
2.3	Letter Agreement dated at April 28, 2009 re: Sections 3.2(i), 7.12, 7.13(b) and 7.20 of the Membership Interest Purchase Agreement by and between Reliant Energy, Inc. and NRG Retail LLC, dated at February 28, 2009 (Incorporated herein by reference to Exhibit 2.3 to the Registrant s Quarterly Report on Form 10-Q filed May 11, 2009)
2.4	Letter Agreement dated at April 9, 2009 re: Section 7.9(iv) of the Membership Interest Purchase Agreement by and between Reliant Energy, Inc. and NRG Retail LLC, dated at February 28, 2009 (Incorporated herein by reference to Exhibit 2.2 to the Registrant s Quarterly Report on Form 10-Q filed May 11, 2009)
2.5	Letter Agreement dated at March 24, 2009 re: Section 7.11 of the Membership Interest Purchase Agreement by and between Reliant Energy, Inc. and NRG Retail LLC, dated at February 28, 2009 (Incorporated herein by reference to Exhibit 2.1 to the Registrant s Quarterly Report on Form 10-Q filed May 11, 2009)
2.6	LLC Membership Interest Purchase Agreement by and between Reliant Energy, Inc. and NRG Retail LLC, dated at February 28, 2009 (Incorporated herein by reference to Exhibit 2.4 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
2.7	Asset Purchase Agreement for Bighorn Power Plant by and among Reliant Energy Wholesale Generation, LLC, Reliant Energy Asset Management, LLC and Nevada Power Company, dated at April 21, 2008 (Incorporated herein by reference to Exhibit 2.1 to the Registrant s Quarterly Report Form 10-Q filed May 1, 2008)
2.8	Amendment No. 1 to Asset Purchase Agreement for Bighorn Power Plant by and among Reliant Energy Wholesale Generation, LLC, Reliant Energy Asset Management, LLC and Nevada Power Company, dated at May 12, 2008 (Incorporated herein by reference to Exhibit 2.2 to the Registrant s Quarterly Report on Form 10-Q filed August 5, 2008)
2.9	Asset Purchase Agreement by and among Reliant Energy Channelview LP, Reliant Energy Services Channelview LLC and GIM Channelview Cogeneration, LLC, entered into June 9, 2008 and dated at April 3, 2008 (Incorporated herein by reference to Exhibit 2.1 to the Registrant s Quarterly Report on Form 10-Q filed August 5, 2008)
2.10	Purchase and Sale Agreement between Mirant International Investments, Inc. and Marubeni Caribbean Power Holdings, Inc., dated at April 17, 2007 (Incorporated herein by reference to Exhibit 2.1 to the Mirant Corporation Current Report on Form 8-K filed April 18, 2007)
2.11	Purchase and Sale Agreement by and between Mirant Americas, Inc. and LS Power Acquisition Co. I, LLC, dated at January 15, 2007 (Incorporated herein by reference to Exhibit 2.1 to the Mirant Corporation Current Report on Form 8-K filed January 18, 2007)
2.12	Stock and Note Purchase Agreement by and among Mirant Asia-Pacific Ventures, Inc., Mirant Asia-Pacific Holdings, Inc., Mirant Sweden International AB (publ), and Tokyo Crimson Energy Holdings Corporation, dated at December 11, 2006 (Incorporated herein by reference to Exhibit 2.1 to

	the Mirant Corporation Current Report on Form 8-K filed December 13, 2006)
3.1	Third Restated Certificate of Incorporation of Registrant (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Quarterly Report on Form 10-Q filed August 2, 2007)
3.2	Certificate of Amendment to the Third Restated Certificate of Incorporation of Registrant, dated at December 3, 2010 (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Form S-8 filed December 3, 2010)

Exhibit No.	Exhibit Name
3.3	Seventh Amended and Restated Bylaws of Registrant, dated at December 3, 2010 (Incorporated herein by reference to Exhibit 4.2 to the Registrant s Form S-8 filed with the Securities and Exchange Commission on December 3, 2010)
4.1	Specimen Stock Certificate (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Registration Statement on Form S-1/A Amendment No. 5, Registration No. 333-48038)
4.2	Rights Agreement between Reliant Resources, Inc. and The Chase Manhattan Bank, as Rights Agent, including a form of Rights Certificate, dated at January 15, 2001 (Incorporated herein by reference to Exhibit 4.2 to the Registrant s Registration Statement on Form S-1/A Amendment No. 8, Registration No. 333-48038)
4.3	Amendment No. 1 to Rights Agreement, by and between RRI Energy, JPMorgan Chase Bank, N.A., and Computershare Trust Company, N.A., dated at November 23, 2010 (Incorporated herein by reference to the Registrant s Current Report on Form 8-K filed November 23, 2010)
4.4	Senior Indenture among Reliant Energy, Inc. and Wilmington Trust Company, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed December 27, 2004, File No. 001-16455)
4.5	First Supplemental Indenture relating to the 6.75% Senior Secured notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed December 27, 2004, File No. 001-16455)
4.6	Second Supplemental Indenture relating to the 6.75% Senior Secured notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated at September 21, 2006 (Incorporated herein by reference to Exhibit 4.18 to the Registrant s Annual Report on Form 10-K filed February 28, 2007)
4.7	Third Supplemental Indenture relating to the 6.75% Senior Secured notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated at December 1, 2006 (Incorporated herein by reference to Exhibit 4.3 to the Registrant s Current Report on Form 8-K filed December 7, 2006)
4.8	Sixth Supplemental Indenture relating to the 6.75% Senior Secured notes due 2014, among RRI Energy, Inc., The Guarantors listed therein and Wilmington Trust Company, dated at June 1, 2009 (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q filed November 5, 2009)
4.9	Seventh Supplemental Indenture relating to the 6.75% Senior Secured notes due 2014, among RRI Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated at August 20, 2009 (Incorporated herein by reference to Exhibit 99.1 to the Registrant s Current Report on Form 8-K filed August 24, 2009)
4.10	Eighth Supplemental Indenture relating to the 6.75% Senior Secured notes due 2014, among RRI Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated at December 1, 2009 (Incorporated herein by reference to Exhibit 4.9 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
4.11	Indenture between Orion Power Holdings, Inc. and Wilmington Trust Company, dated at April 27, 2000 (Incorporated herein by reference to Exhibit 4.1 to the Orion Power Holdings, Inc. Registration Statement on Form S-1, Registration No. 333-44118)
4.12	Fourth Supplemental Indenture relating to the 7.625% Senior notes due 2014, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated at June 13, 2007 (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed

	June 15, 2007)
4.13	Fifth Supplemental Indenture relating to the 7.875% Senior notes due 2017, among Reliant Energy, Inc., the Guarantors listed therein and Wilmington Trust Company, dated at June 13, 2007 (Incorporated herein by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed June 15, 2007)

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Exhibit No.	Exhibit Name
4.14	Indenture between Mirant Americas Generation, Inc. and Bankers Trust Company, as trustee, relating to Senior Notes, dated at May 1, 2001 (Incorporated herein by reference to Exhibit 4.1 to the Mirant Americas Generation, Inc. Registration Statement on Form S-4, Registration No. 333-63240)
4.15	Second Supplemental Indenture relating to Senior Notes 8.300% due 2011, dated at May 1, 2001 (Incorporated herein by reference to Exhibit 4.3 to the Mirant Americas Generation, Inc. Registration Statement on Form S-4, Registration No. 333-63240)
4.16	Third Supplemental Indenture from Mirant Americas Generation, Inc. to Bankers Trust Company, relating to 9.125% Senior Notes due 2031, dated at May 1, 2001 (Incorporated herein by reference to Exhibit 4.4 to the Mirant Americas Generation, Inc. Registration Statement on Form S-4, Registration No. 333-63240)
4.17	Fifth Supplemental Indenture from Mirant Americas Generation, Inc. to Bankers Trust Company, dated at October 9, 2001 (Incorporated herein by reference to Exhibit 4.6 to the Mirant Americas Generation, Inc. Registration Statement on Form S-4/A Amendment No. 1, Registration No. 333-85124)
4.18	Form of Sixth Supplemental Indenture from Mirant Americas Generation LLC to Bankers Trust Company, dated at November 1, 2001 (Incorporated herein by reference to Exhibit 4.6 to the Mirant Corporation Annual Report on Form 10-K filed February 27, 2009)
4.19	Form of Seventh Supplemental Indenture from Mirant Americas Generation LLC to Wells Fargo Bank National Association, dated at January 3, 2006 (Incorporated herein by reference to Exhibit 4.1 to the Mirant Americas Generation, LLC Quarterly Report on Form 10-Q filed May 14, 2007)
4.20	Senior Note Indenture between Mirant North America, LLC, Mirant North America Escrow, LLC, MNA Finance Corp. and Law Debenture Trust Company of New York, as trustee (Incorporated herein by reference to Exhibit 4.2 to the Mirant Corporation Annual Report on Form 10-K filed March 14, 2006)
4.21	Form of 8.625% Series A Pass Through Certificate (Incorporated herein by reference to Exhibit 4.1 to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.22	Form of 9.125% Series B Pass Through Certificate (Incorporated herein by reference to Exhibit 4.2 to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.23	Form of 10.060% Series C Pass Through Certificate (Incorporated herein by reference to Exhibit 4.3 to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.24(a)	Pass Through Trust Agreement A between Southern Energy Mid-Atlantic, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, dated at December 18, 2000 (Incorporated herein by reference to Exhibit 4.4(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.24(b)	Schedule identifying substantially identical agreement to Pass Through Trust Agreement A (Incorporated herein by reference to Exhibit 4.4(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.25(a)	Participation Agreement (L1) among Southern Energy Mid-Atlantic, LLC, as Lessee, Dickerson OL1 LLC, as Owner Lessor, Wilmington Trust Company, as Owner Manager, SEMA OP3 LLC, as Owner Participant and State Street Bank and Trust Company of Connecticut, National Association, as Lease Indenture Trustee and as Pass Through Trustee, dated at December 18, 2000 (Incorporated herein by reference to Exhibit 4.5(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.25(b)	Schedule identifying substantially identical agreements to Participation Agreement (Incorporated herein by reference to Exhibit 4.5(b) to the Mirant Mid-Atlantic, LLC Registration Statement on

Form S-4, Registration No. 333-61668)

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Exhibit No.	Exhibit Name
4.26(a)	Participation Agreement (L1) among Southern Energy Mid-Atlantic, LLC, as Lessee, Morgantown OL1 LLC, as Owner Lessor, Wilmington Trust Company, as Owner Manager, SEMA OP1 LLC, as Owner Participant and State Street Bank and Trust Company of Connecticut, National Association, as Lease Indenture Trustee and as Pass Through Trustee, dated at December 18, 2000 (Incorporated herein by reference to Exhibit 4.6a to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.26(b)	Schedule identifying substantially identical agreement to Participation Agreement (Incorporated herein by reference to Exhibit 4.6(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.27(a)	Facility Lease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, as Facility Lessee, and Dickerson OL1 LLC, as Owner Lessor, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.7(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.27(b)	Schedule identifying substantially identical agreement to Facility Lease Agreement (Incorporated herein by reference to Exhibit 4.7(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.28(a)	Facility Lease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, as Facility Lessee, and Morgantown OL1 LLC, as Owner Lessor, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.8(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.28(b)	Schedule identifying substantially identical agreement to Facility Lease Agreement (Incorporated herein by reference to Exhibit 4.8(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.29(a)	Indenture of Trust, Mortgage and Security Agreement (L1) between Dickerson OL1 LLC, as Lessor, and State Street Bank and Trust Company of Connecticut, National Association, as Lease Indenture Trustee, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.9(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.29(b)	Schedule identifying substantially identical agreement to Indenture of Trust, Mortgage and Security Agreement (Incorporated herein by reference to Exhibit 4.9(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.30(a)	Indenture of Trust, Mortgage and Security Agreement (L1) between Morgantown OL1 LLC, as Lessor, and State Street Bank and Trust Company of Connecticut, National Association, as Lease Indenture Trustee, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.10(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.30(b)	Schedule identifying substantially identical agreement to Indenture of Trust, Mortgage and Security Agreement (Incorporated herein by reference to Exhibit 4.10(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.31(a)	Series A Lessor Note Due June 20, 2012 for Dickerson OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.11(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.31(b)	Schedule identifying substantially identical Lessor Notes (Incorporated herein by reference to Exhibit 4.11(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.32(a)	Series A Lessor Note Due June 30, 2008, for Morgantown OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.12(a) to the Mirant Mid-Atlantic, LLC Registration

	Statement on Form S-4, Registration No. 333-61668)
4.32(b)	Schedule identifying substantially Series A Lessor Notes (Incorporated herein by reference to Exhibit 4.12(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)

Exhibit No.	Exhibit Name
4.33(a)	Series B Lessor Note Due June 30, 2015, for Dickerson OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.13(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.33(b)	Schedule identifying substantially Lessor Note (Incorporated herein by reference to Exhibit 4.13(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.34(a)	Series B Lessor Note Due June 30, 2017, for Morgantown OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.14(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.34(b)	Schedule identifying substantially identical Lessor Notes (Incorporated herein by reference to Exhibit 4.14(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.35(a)	Series C Lessor Note Due June 30, 2020, for Morgantown OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 4.15(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.35(b)	Schedule identifying substantially identical Lessor Notes (Incorporated herein by reference to Exhibit 4.15(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
4.36(a)	Supplemental Pass Through Trust Agreement A between Mirant Mid-Atlantic, LLC, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, dated at June 29, 2001 (Incorporated herein by reference to Exhibit 4.17(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4/A Registration No. 333-61668)
4.36(b)	Schedule identifying substantially identical agreements to Supplemental Pass Through Trust Agreement for Supplemental Pass Through Trust Agreement B between Mirant Mid-Atlantic, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, dated at June 29, 2001, and Supplemental Pass Through Trust Agreement C between Mirant Mid-Atlantic, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, dated at June 29, 2001 (Incorporated herein by reference to Exhibit 4.17(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4/A, Registration No. 333-61668)
4.37	Senior Notes Indenture, relating to the 9.5% Senior Notes Due 2018 and the 9.875% Senior Notes Due 2020, by GenOn Escrow Corp. and Wilmington Trust Company as trustee, dated at October 4, 2010 (Incorporated by reference to Exhibit 4.4 to the Mirant Corporation Quarterly Report on Form 10-Q filed November 5, 2010)
4.38	Supplemental Indenture, relating to the 9.5% Senior Notes due 2018 and the 9.875% Senior Notes Due 2020, by GenOn Energy, Inc. and Wilmington Trust Company as trustee, dated at December 3, 2010 (Incorporated by reference to Exhibit 4.2 to the Registrant s Current Report on Form 8-K filed December 7, 2010)
10.1.1(a)	Master Separation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated at December 31, 2000 (Incorporated herein by reference to Exhibit 10.1 to the CenterPoint Energy Houston Electric, LLC Quarterly Report on Form 10-Q filed May 14, 2001, File No. 001-03187)
10.1.1(b)	Schedule to Master Separation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated at December 31, 2000 (Incorporated herein by reference to Exhibit 10.1B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.2(a)	Tax Allocation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated at December 31, 2000 (Incorporated herein by reference to Exhibit 10.8 to the CenterPoint Energy Houston Electric, LLC Quarterly Report on Form 10-Q filed May 14, 2001, File No. 001-03187)

Exhibit No.	Exhibit Name
10.1.2(b)	Exhibit to Tax Allocation Agreement between Reliant Resources, Inc. and Reliant Energy, Incorporated, dated at December 31, 2000 (Incorporated herein by reference to Exhibit 10.2B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.3	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed December 27, 2004, File No. 001-16455)
10.1.4(a)	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.3 to the Registrant s Current Report on Form 8-K filed December 27, 2004, File No. 001-16455)
10.1.4(b)	Exhibit C Form of Supplement to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.5B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.5(a)	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.4 to the Registrant s Current Report on Form 8-K filed December 27, 2004, File No. 001-16455)
10.1.5(b)	Exhibit C Form of Supplement to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.6B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.6(a)	Exhibit C Form of Supplement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.5 to the Registrant s Current Report on Form 8-K filed December 27, 2004, File No. 001-16455)
10.1.6(b)	Exhibit C Form of Supplement to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.7B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.7(a)	Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National

Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.6 to the Registrant s Current Report on Form 8-K filed December 27, 2004, File No. 001-16455)

Exhibit No.	Exhibit Name
10.1.7(b)	Exhibit C Form of Supplement to Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among Reliant Energy, Inc., the Subsidiary Guarantors defined therein and J.P. Morgan Trust Company, National Association, as trustee, dated at December 22, 2004 (Incorporated herein by reference to Exhibit 10.8B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.8	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated at September 21, 2006 (Incorporated herein by reference to Exhibit 10.14 to the Registrant s Annual Report on Form 10-K filed February 28, 2007)
10.1.9	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated at September 21, 2006 (Incorporated herein by reference to Exhibit 10.15 to the Registrant s Annual Report on Form 10-K filed February 28, 2007)
10.1.10	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated at September 21, 2006 (Incorporated herein by reference to Exhibit 10.16 to the Registrant s Annual Report on Form 10-K filed February 28, 2007)
10.1.11	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, National Association, as trustee, dated at September 21, 2006 (Incorporated herein by reference to Exhibit 10.17 to the Registrant s Annual Report on Form 10-K filed February 28, 2007)
10.1.12	Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among Reliant Energy Power Supply, LLC, Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and J.P. Morgan Trust Company, as trustee, dated at September 21, 2006 (Incorporated herein by reference to Exhibit 10.18 to the Registrant s Annual Report on Form 10-K filed February 28, 2007)
10.1.13	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at December 1, 2006 (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed December 7, 2006)
10.1.14	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee

Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at December 1, 2006 (Incorporated herein by reference to Exhibit 10.2 to the Registrant s Current Report on Form 8-K filed December 7, 2006)

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Exhibit No.	Exhibit Name
10.1.15	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at December 1, 2006 (Incorporated herein by reference to Exhibit 10.3 to the Registrant s Current Report on Form 8-K filed December 7, 2006)
10.1.16	Second Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at December 1, 2006 (Incorporated herein by reference to Exhibit 10.4 to the Registrant s Current Report on Form 8-K filed December 7, 2006)
10.1.17	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among Reliant Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at December 1, 2006 (Incorporated herein by reference to Exhibit 10.5 to the Registrant s Current Report on Form 8-K filed December 7, 2006)
10.1.18	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at June 1, 2009 (Incorporated herein by reference to Exhibit 10.2 to the Registrant s Quarterly Report on Form 10-Q filed November 5, 2009)
10.1.19	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at June 1, 2009 (Incorporated herein by reference to Exhibit 10.3 to the Registrant s Quarterly Report on Form 10-Q filed November 5, 2009)
10.1.20	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at June 1, 2009 (Incorporated herein by reference to Exhibit 10.4 to the Registrant s Quarterly Report on Form 10-Q filed November 5, 2009)
10.1.21	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at June 1, 2009 (Incorporated herein by reference to Exhibit 10.5 to the Registrant s Quarterly Report on Form 10-Q filed November 5, 2009)
10.1.22	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated at June 1, 2009 (Incorporated herein by reference to Exhibit 10.6 to the Registrant s Quarterly Report on Form 10-Q filed November 5, 2009)

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Exhibit No.	Exhibit Name
10.1.23	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at August 20, 2009 (Incorporated herein by reference to Exhibit 99.3 to the Registrant s Current Report on Form 8-K filed August 24, 2009)
10.1.24	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at August 20, 2009 (Incorporated herein by reference to Exhibit 99.4 to the Registrant s Current Report on Form 8-K filed August 24, 2009)
10.1.25	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at August 20, 2009 (Incorporated herein by reference to Exhibit 99.5 to the Registrant s Current Report on Form 8-K filed August 24, 2009)
10.1.26	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at August 20, 2009 (Incorporated herein by reference to Exhibit 99.6 to the Registrant s Current Report on Form 8-K filed August 24, 2009)
10.1.27	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at December 1, 2009 (Incorporated herein by reference to Exhibit 10.29 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.28	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at December 1, 2009 (Incorporated herein by reference to Exhibit 10.30 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.29	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at December 1, 2009 (Incorporated herein by reference to Exhibit 10.31 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.30	Fifth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The

Bank of New York Mellon Trust Company, N.A., as trustee, dated at December 1, 2009 (Incorporated herein by reference to Exhibit 10.32 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)

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Exhibit No.	Exhibit Name
10.1.31	Sixth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenues Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among RRI Energy, Inc. the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Mellon Trust Company, N.A., as trustee, dated at December 1, 2009 (Incorporated herein by reference to Exhibit 10.33 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.32(a)	Credit and Guaranty Agreement among Reliant Energy, Inc., as Borrower, the Other Loan Parties referred to therein as guarantors, the lenders party thereto, Deutsche Bank AG New York Branch, as Administrative Agent and Collateral Agent, Deutsche Bank Securities Inc. and J.P. Morgan Securities Inc., as Joint Lead Arrangers, Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation, and ABN AMRO Bank N.V., as Joint Bookrunners with respect to the Revolving Credit Facility and Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation and Bear Sterns & Co. Inc., as Joint Bookrunners with respect to the Pre-Funded L/C Facility, dated at June 12, 2007 (Incorporated herein by reference to Exhibit 1.1 to the Registrant s Current Report on Form 8-K filed June 15, 2007)
10.1.32(b)	Exhibits and Schedules to Credit and Guaranty Agreement among Reliant Energy, Inc., as Borrower, the Other Loan Parties referred to therein as guarantors, the lenders party thereto, Deutsche Bank AG New York Branch, as Administrative Agent and Collateral Agent, Deutsche Bank Securities Inc. and J.P. Morgan Securities Inc., as Joint Lead Arrangers, Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation and ABN AMRO Bank N.V., as Joint Bookrunners with respect to the Revolving Credit Facility and Deutsche Bank Securities Inc., J.P. Morgan Securities Inc., Goldman Sachs Credit Partners L.P., Merrill Lynch Capital Corporation, and Bear Sterns & Co. Inc., as Joint Bookrunners with respect to the Pre-Funded L/C Facility, dated at June 12, 2007 (Incorporated herein by reference to Exhibit 10.34B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.33	Schedule identifying substantially identical agreements to Pass Through Trust Agreement constituting Exhibit 10.1.35 (Incorporated herein by reference to Exhibit 4.4b to the RRI Energy Mid-Atlantic Power Holdings, LLC Registration Statement on Form S-4, Registration No. 333-51464)
10.1.34	Participation Agreement among Conemaugh Lessor Genco LLC, as Owner Lessor, Reliant Energy Mid-Atlantic Power Holdings, LLC, as Facility Lessee, Wilmington Trust Company, as Lessor Manager, PSEGR Conemaugh Generation, LLC, as Owner Participant, (v) Bankers Trust Company, as Lease Indenture Trustee, and (vi) Bankers Trust Company, as Pass Through Trustee, dated at August 24, 2000 (Incorporated herein by reference to Exhibit 4.5a to the RRI Energy Mid-Atlantic Power Holdings, LLC Registration Statement on Form S-4, Registration No. 333-51464)
10.1.35	Schedule identifying substantially identical agreements to Participation Agreement constituting Exhibit 10.1.37 (Incorporated herein by reference to Exhibit 4.5b to the RRI Energy Mid-Atlantic Power Holdings, LLC Registration Statement on Form S-4, Registration No. 333-51464)
10.1.36(a)	First Amendment to Participation Agreement constituting Exhibit 10.1.37, dated at November 15, 2001 (Incorporated herein by reference to Exhibit 10.20 to the Registrant s Annual Report on Form 10-K filed March 15, 2006)
10.1.36(b)	Exhibit M to First Amendment to Participation Agreement constituting Exhibit 10.1.36(a), dated at November 15, 2001 (Incorporated herein by reference to Exhibit 10.41B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.37	

Schedule identifying substantially identical agreements to First Amendment to Participation Agreement constituting Exhibit 10.1.36(a) (Incorporated herein by reference to Exhibit 10.21 to the Registrant s Annual Report on Form 10-K filed March 15, 2006)

Exhibit No.	Exhibit Name
10.1.38	Second Amendment to Participation Agreement, dated at June 18, 2003 (Incorporated herein by reference to Exhibit 10.22 to the Registrant s Annual Report on Form 10-K filed March 15, 2006)
10.1.39	Schedule identifying substantially identical agreements to Second Amendment to Participation Agreement constituting Exhibit 10.1.38 (Incorporated herein by reference to Exhibit 10.23 to the Registrant s Annual Report on Form 10-K filed March 15, 2006)
10.1.40(a)	Purchase and Sale Agreement by and between Orion Power Holdings, Inc., Reliant Energy, Inc., Great Lakes Power Inc. and Brascan Corporation, dated at May 18, 2004 (Incorporated herein by reference to Exhibit 99.2 to the Registrant s Current Report on Form 8-K filed May 21, 2004, File No. 001-16455)
10.1.40(b)	Schedules to Purchase and Sale Agreement by and between Orion Power Holdings, Inc., Reliant Energy, Inc., Great Lakes Power Inc. and Brascan Corporation, dated at May 18, 2004 (Incorporated herein by reference to Exhibit 10.47B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.41(a)	Purchase and Sale Agreement between Orion Power Holdings, Inc., as Seller, Reliant Energy, Inc., as Guarantor, and Astoria Generating Company Acquisitions, L.L.C., as Buyer, dated at September 30, 2005 (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed October 6, 2005, File No. 001-16455)
10.1.41(b)	Exhibits and Schedules to Purchase and Sale Agreement between Orion Power Holdings, Inc., as Seller, Reliant Energy, Inc., as Guarantor, and Astoria Generating Company Acquisitions, L.L.C., as Buyer, dated at September 30, 2005 (Incorporated herein by reference to Exhibit 10.48B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.1.42	Guarantee by NRG Energy, Inc., as Guarantor, in favor of Reliant Energy, Inc., dated at February 28, 2009 (Incorporated herein by reference to Exhibit 10.84 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
10.1.43	Credit Agreement among Mirant North America, LLC, JPMorgan Chase Bank, N.A as administrative agent and Deutsche Bank Securities Inc. and Goldman Sachs Credit Partners L.P., as co-syndication agents, dated at January 3, 2006 (Incorporated herein by reference to Exhibit 10.2 to the Mirant Corporation Quarterly Report on Form 10-Q filed November 6, 2009)
10.1.44(a)	Guaranty Agreement (Dickerson L1) between Southern Energy, Inc. and Dickerson OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.21(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.1.44(b)	Schedule identifying substantially identical agreements to Guaranty Agreement constituting Exhibit 10.1.45(a) (Incorporated herein by reference to Exhibit 10.21(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.1.45(a)	Guaranty Agreement (Morgantown L1) between Southern Energy, Inc. and Morgantown OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.22(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.1.45(b)	Schedule identifying substantially identical agreements to Guaranty Agreement constituting Exhibit 10.1.45(a) (Incorporated herein by reference to Exhibit 10.22(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.1.46	Credit Agreement by and among RRI Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities, Inc., Goldman Sachs Bank USA, Morgan Stanley Senior Funding, Inc., Royal Bank of Canada, The Royal Bank of Scotland plc, the other lenders from time to time party thereto and, from and after the closing date of the merger, Mirant Americas, Inc. (to be renamed GenOn Americas, Inc. on the closing date of the merger), dated

at September 20, 2010 (Incorporated herein by reference to the Mirant Corporation Quarterly Report on Form 10-Q filed November 5, 2010)

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Exhibit No.	Exhibit Name
10.1.47	Purchase Agreement by and among RRI Energy, Inc., Mirant Corporation, GenOn Escrow Corp. and J.P. Morgan Securities LLC, as representative of the several initial purchasers, dated at September 20, 2010 (Incorporated herein by reference to the Mirant Corporation Quarterly Report on Form 10-Q filed November 5, 2010)
10.1.48*	Credit Agreement among Mirant Marsh Landing, LLC, the Royal Bank of Scotland PLC, as administrative agent and Deutsche Bank Trust Company Americas, as Collateral Agent and Depository Bank, dated as of October 8, 2010
10.1.49*	Security Agreement between Mirant Marsh Landing, LLC and Deutsche Bank Trust Company Americas, as Collateral Agent, dated as of October 8, 2010
10.1.50*	Pledge Agreement among Marsh Landing Holdings, LLC, Mirant Marsh Landing, LLC and Deutsche Bank Trust Company Americas, as Collateral Agent, dated at October 8, 2010
10.1.51*	Collateral Agency and Intercreditor Agreement among Mirant Marsh Landing, LLC, The Royal Bank of Scotland PLC, as administrative agent, and Deutsche Bank Trust Company Americas, as Collateral Agent and Depository Bank, dated at October 8, 2010
10.1.52*	Equity Contribution Agreement among Mirant Corporation, Mirant Marsh Landing, LLC, The Royal Bank of Scotland PLC, as administrative agent, and Deutsche Bank Trust Company Americas, as Collateral Agent, dated as of October 8, 2010
10.2.1	Registrant s Transition Stock Plan, effective at May 4, 2001 (Incorporated herein by reference to Exhibit 10.37 to the Registrant s Annual Report on Form 10-K filed April 15, 2002, File No. 001-16455)
10.2.2	Registrant s 2002 Stock Plan, effective at March 1, 2002 (Incorporated herein by reference to Exhibit 4.5 to the Registrant s Registration Statement on Form S-8, Registration No. 333-86610)
10.2.3	Registrant s Annual Incentive Compensation Plan, effective at January 1, 2001 (Incorporated herein by reference to Exhibit 10.9 to the Registrant s Annual Report on Form 10-K filed April 15, 2002, File No. 001-16455)
10.2.4	First Amendment to Registrant s Annual Incentive Compensation Plan, dated at September 27, 2007 (Incorporated herein by reference to Exhibit 10.44 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
10.2.5	Registrant s 2002 Annual Incentive Compensation Plan for Executive Officers, effective at March 1, 2002 (Incorporated herein by reference to Appendix I to the Registrant s 2002 Proxy Statement on Schedule 14A filed April 30, 2002, File No. 001-16455)
10.2.6	First Amendment to Registrant s 2002 Annual Incentive Compensation Plan for Executive Officers, dated at September 27, 2007 (Incorporated herein by reference to Exhibit 10.46 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
10.2.7	Long-Term Incentive Plan of Registrant, effective at January 1, 2001 (Incorporated herein by reference to Exhibit 10.10 to the Registrant s Annual Report on Form 10-K filed April 15, 2002, File No. 001-16455)
10.2.8	Registrant s 2002 Long-Term Incentive Plan, effective at June 6, 2002 (Incorporated herein by reference to Exhibit 4.5 to the Registrant s Registration Statement on Form S-8, Registration No. 333-86612)
10.2.9	Registrant s Deferral Plan, effective at January 1, 2002 (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Registration Statement on Form S-8, Registration No. 333-74790)
10.2.10	First Amendment to Registrant s Deferral Plan, effective at January 14, 2003 (Incorporated herein by reference to Exhibit 10.5 to the Registrant s Annual Report on Form 10-K filed March 8, 2004, File No. 001-16455)

10.2.11	Second Amendment to Registrant s Deferral Plan, effective at December 31, 2004 (Incorporated herein by reference to Exhibit 10.51 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)

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Exhibit No.	Exhibit Name
10.2.12	Registrant s Deferral and Restoration Plan, effective at January 1, 2005 (Incorporated herein by reference to Exhibit 10.52 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
10.2.13	Registrant s Successor Deferral Plan, effective at January 1, 2002 (Incorporated herein by reference to Exhibit 10.30 to the Registrant s Annual Report on Form 10-K filed March 15, 2005, File No. 001-16455)
10.2.14	Registrant s Deferred Compensation Plan, effective at September 1, 1985, including the first nine amendments thereto (This is now a part of the plan listed as Exhibit 10.2.14) (Incorporated herein by reference to Exhibit 10.25 to the Registrant s Registration Statement on Form S-1/A Amendment No. 8, Registration No. 333-48038)
10.2.15	Registrant s Deferred Compensation Plan, as amended and restated effective at January 1, 1989, including the first nine amendments thereto (This is now a part of the plan listed as Exhibit 10.2.14) (Incorporated herein by reference to Exhibit 10.26 to the Registrant s Registration Statement on Form S-1/A Amendment No. 8, Registration No. 333-48038)
10.2.16	Registrant s Deferred Compensation Plan, as amended and restated effective at January 1, 1991, including the first ten amendments thereto (This is now a part of the plan listed as Exhibit 10.2.14) (Incorporated herein by reference to Exhibit 10.27 to the Registrant s Registration Statement on Form S-1/A Amendment No. 8, Registration No. 333-48038)
10.2.17	Registrant s Benefit Restoration Plan, as amended and restated effective at July 1, 1991, including the first amendment thereto (This is now a part of the plan listed as Exhibit 10.2.14) (Incorporated herein by reference to Exhibit 10.12 to the Registrant s Registration Statement on Form S-1/A Amendment No. 8, Registration No. 333-48038)
10.2.18(a)	Key Employee Award Program 2004-2006 of Registrant s 2002 Long-Term Incentive Plan and the Form of Agreement for Key Employee Award Program, effective at February 13, 2004 (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q filed August 4, 2004, File No. 001-16455)
10.2.18(b)	Exhibit B to Key Employee Award Program 2004-2006 of the Registrant s 2002 Long-Term Incentive Plan and the Form of Agreement for Key Employee Award Program, effective at February 13, 2004 (Incorporated herein by reference to Exhibit 10.68B to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.2.19	First Amendment to the Key Employee Award Program, effective at August 10, 2005 (Incorporated herein by reference to Exhibit 10.44 to the Registrant s Annual Report on Form 10-K filed March 15, 2006)
10.2.20	Form of 2002 Stock Plan Nonqualified Stock Option Award Agreement, 2003 Grants (Incorporated herein by reference to Exhibit 10.39 to the Registrant s Annual Report on Form 10-K filed March 15, 2005, File No. 001-16455)
10.2.21	Form of Change in Control Agreement for CEO, CFO and COO (Incorporated herein by reference to Exhibit 10.61 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
10.2.22	Form of Change in Control Agreement for certain officers other than CEO, CFO and COO (Incorporated herein by reference to Exhibit 10.62 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
10.2.23	Registrant s Executive Severance Plan, effective at January 1, 2006 (Incorporated herein by reference to Exhibit 10.57 to the Registrant s Annual Report on Form 10-K filed March 15, 2006)
10.2.24	First Amendment to Registrant s Executive Severance Plan, dated at September 27, 2007 (Incorporated herein by reference to Exhibit 10.64 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)

10.2.25	Form of Registrant s 2002 Long-Term Incentive Plan Nonqualified Stock Option Award Agreement (Incorporated herein by reference to Exhibit 10.53 to the Registrant s Annual Report on Form 10-K filed March 15, 2005, File No. 001-16455)

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Exhibit No.	Exhibit Name
10.2.26	Form of Registrant s 2002 Long-Term Incentive Plan Restricted Stock Award Agreement (Incorporated herein by reference to Exhibit 10.54 to the Registrant s Annual Report on Form 10-K filed March 15, 2005, File No. 001-16455)
10.2.27	Reliant Energy, Inc. Non-Employee Directors Compensation Program, effective at October 13, 2008 (Incorporated herein by reference to Exhibit 10.72 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)
10.2.28	2002 Long-Term Incentive Plan 2008 Long-Term Incentive Award Program for Officers (Form of Agreement included with Program) (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q filed May 1, 2008)
10.2.29	2002 Long-Term Incentive Plan 2007 Long-Term Incentive Award Program for Officers (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q filed May 3, 2007)
10.2.30	Form of 2002 Long-Term Incentive Plan 2007 Long-Term Incentive Award Agreement for Officers (Incorporated herein by reference to Exhibit 10.2 to the Registrant s Quarterly Report on Form 10-Q filed May 3, 2007)
10.2.31	2002 Long-Term Incentive Plan 2007 Long-Term Incentive Award Agreement for Mark Jacobs (Incorporated herein by reference to Exhibit 10.3 to the Registrant s Quarterly Report on Form 10-Q filed August 2, 2007)
10.2.32	2002 Long-Term Incentive Plan Amendment to Nonqualified Stock Option Award Agreement by and between Reliant Energy, Inc. and Joel V. Staff, dated at May 16, 2007 March 12, 2003 grant (Incorporated herein by reference to Exhibit 10.4 to the Registrant s Quarterly Report on Form 10-Q filed August 2, 2007)
10.2.33	2002 Long-Term Incentive Plan Amendment to Nonqualified Stock Option Award Agreement by and between Reliant Energy, Inc. and Joel V. Staff, dated at May 16, 2007 May 8, 2003 grant (Incorporated herein by reference to Exhibit 10.5 to the Registrant s Quarterly Report on Form 10-Q filed August 2, 2007)
10.2.34	2002 Long-Term Incentive Plan Amendment to Nonqualified Stock Option Award Agreement by and between Reliant Energy, Inc. and Joel V. Staff, dated at May 16, 2007 August 23, 2003 grant (Incorporated herein by reference to Exhibit 10.6 to the Registrant s Quarterly Report on Form 10-Q filed August 2, 2007)
10.2.35	2002 Long-Term Incentive Plan Amendment to Key Employee Award Program 2004-2006 Agreement by and between Reliant Energy, Inc. and Joel V. Staff, dated at May 16, 2007 February 13, 2004 grant (Incorporated herein by reference to Exhibit 10.7 to the Registrant s Quarterly Report on Form 10-Q filed August 2, 2007)
10.2.36	2002 Long-Term Incentive Plan Long-Term Incentive Award Agreement for Rick J. Dobson (Incorporated herein by reference to Exhibit 10.2 to the Registrant s Quarterly Report on Form 10-Q filed November 8, 2007)
10.2.37	2002 Long-Term Incentive Plan Long-Term Incentive Award Agreement for Albert H. Myres, Sr. (Incorporated herein by reference to Exhibit 10.77 to the Registrant s Annual Report on Form 10-K filed February 26, 2008)
10.2.38	2002 Long-Term Incentive Plan Long-Term Incentive Award Agreement for Charles Griffey (Incorporated herein by reference to Exhibit 10.78 to the Registrant s Annual Report on Form 10-K filed February 26, 2008)
10.2.39	2009 Long Term Incentive Award Program for Officers and Form of Award Agreement (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q filed August 3,

	2009)
10.2.40	Non-Employee Directors Compensation Program, effective at June 19, 2009 (Incorporated herein by reference to Exhibit 10.5 to the Registrant s Quarterly Report on Form 10-Q filed August 3, 2009)

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Exhibit No.	Exhibit Name
10.2.41	Non-Employee Directors Compensation Program, effective at January 1, 2010 (Incorporated herein by reference to Exhibit 10.99 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.2.42	2002 Long Term Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors (Incorporated herein by reference to Exhibit 10.100 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.2.43	Registrant s 2002 Long Term Incentive Plan 2009 for Officers (Form of 2009 Long Term Incentive Award Agreement Included with Program) (Incorporated herein by reference to Exhibit 10.101 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.2.44	Omnibus Amendment to Registrant s Executive Deferral, Incentive and Non-Qualified Plans effective at May 2, 2009 (amending plans filed as Exhibits 10.2.2, 10.2.3, 10.2.4, 10.2.6, 10.2.8, 10.2.9, 10.2.10, 10.2.13 and 10.2.14) (Incorporated herein by reference to Exhibit 10.104 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.2.45	Omnibus Amendment to Registrant s Severance Plans effective at May 2, 2009 (amending plans filed as Exhibits 10.2.2, 10.2.3, 10.2.4, 10.2.6, 10.2.8, 10.2.9, 10.2.10, 10.2.13 and 10.2.14) (Incorporated herein by reference to Exhibit 10.105 to the Registrant s Annual Report on Form 10-K filed February 25, 2010)
10.2.46	Registrant s 2002 Long Term Incentive Plan Form of 2010 Long-Term Incentive Award Agreement for Officers (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Quarterly Report on Form 10-Q filed May 6, 2010)
10.2.47	Retention Incentive Agreement between RRI Energy, Inc. and Mark M. Jacobs, dated at April 22, 2010 (Incorporated herein by reference to Exhibit 10.2 to the Registrant s Registration Statement on Form S-4, File No. 333-167192)
10.2.48	Amendment to Change in Control Agreement, dated at April 11, 2010, between RRI Energy, Inc. and Mark M. Jacobs (Incorporated herein by reference to Exhibit 10.3 to the Registrant s Registration Statement on Form S-4, File No. 333-167192)
10.2.49	Amendment to Change in Control Agreement, dated at April 11, 2010, between RRI Energy, Inc. and Michael L. Jines (Incorporated herein by reference to Exhibit 10.4 to the Registrant s Registration Statement on Form S-4, File No. 333-167192)
10.2.50	Form of Mirant Corporation Stock Option Award Agreement (Incorporated herein by reference to Exhibit 10.1 to the Mirant Corporation Current Report on Form 8-K filed November 16, 2006)
10.2.51	Form of Mirant Corporation Restricted Stock Unit Award Agreement (Incorporated herein by reference to Exhibit 10.2 to the Mirant Corporation Current Report on Form 8-K filed November 16, 2006)
10.2.52	Description of Mirant Corporation special bonus plan (Incorporated herein by reference to the Mirant Corporation Current Report on Form 8-K filed October 11, 2006)
10.2.53	Mirant Corporation 2006 Non-Employee Directors Compensation Plan, as amended at August 7, 2008 (Incorporated herein by reference to Exhibit 10.1 to the Mirant Corporation Quarterly Report on Form 10-Q filed November 7, 2008)
10.2.54	Mirant Corporation 2006 Short-term Incentive Plan Description (Incorporated herein by reference to Exhibit 10.55 to the Mirant Corporation Annual Report on Form 10-K filed March 14, 2006)
10.2.55	Form of Stock Option Award Agreement (Incorporated herein by reference to Exhibit 10.1 to the Mirant Corporation Current Report on Form 8-K filed January 18, 2006, File No. 001-16107)
10.2.56	Mirant Corporation Form of Restricted Stock Unit Award Agreement (Incorporated herein by reference to Exhibit 10.2 to the Mirant Corporation Current Report on Form 8-K filed January 18, 2006)

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Exhibit No.	Exhibit Name
10.2.57	Mirant Corporation 2005 Omnibus Incentive Compensation Plan, effective December 2005 (Incorporated herein by reference to Exhibit 10.1 to the Mirant Corporation Current Report on Form 8-K filed January 3, 2006, File No. 001-16107)
10.2.58	Second Amended and Restated Mirant Services Supplemental Executive Retirement Plan, effective at January 1, 2009 (Incorporated herein by reference to Exhibit 10.18 to the Mirant Corporation Annual Report on Form 10-K filed February 27, 2009)
10.2.59	Mirant Corporation Deferred Compensation Plan, effective at April 1, 2006 (Incorporated herein by reference to Exhibit 10.23 to the Mirant Corporation Annual Report on Form 10-K filed March 14, 2006)
10.2.60	First Amendment to the 2006 Mirant Corporation Deferred Compensation Plan, effective at January 1, 2009 (Incorporated herein by reference to Exhibit 10.20 to the Mirant Corporation Annual Report on Form 10-K filed February 27, 2009)
10.2.61	Mirant Services Supplemental Benefit (Savings) Plan, amended and restated effective at January 1, 2009 (Incorporated herein by reference to Exhibit 10.21 to the Mirant Corporation Annual Report on Form 10-K filed February 27, 2009)
10.2.62	Mirant Services Supplemental Benefit (Pension) Plan, amended and restated effective at January 1, 2009 (Incorporated herein by reference to Exhibit 10.22 to the Mirant Corporation Annual Report on Form 10-K filed February 27, 2009)
10.2.63	Form of Amended and Restated Mirant Corporation Deferred Compensation Plan for Directors and Select Employees (Incorporated herein by reference to Exhibit 10.55 to the Mirant Corporation Annual Report on Form 10-K filed March 11, 2002, File No. 001-16107)
10.2.64	First Amendment to the Mirant Corporation Deferred Compensation Plan for Directors and Select Employees (Incorporated herein by reference to Exhibit 10.56 to the Mirant Corporation Annual Report on Form 10-K filed March 11, 2002, File No. 001-16107)
10.2.65	Second Amendment to the Mirant Corporation Deferred Compensation Plan for Directors and Select Employees, effective at July 30, 2003 (Incorporated herein by reference to Exhibit 10.87 to the Mirant Corporation Quarterly Report on Form 10-Q filed October 28, 2003, File No. 001-16107)
10.2.66	Third Amendment to the Mirant Corporation Deferred Compensation Plan for Directors and Select Employees, effective at August 27, 2004 (Incorporated herein by reference to Exhibit 10.43 to the Mirant Corporation Annual Report on Form 10-K filed March 15, 2005, File No. 001-16107)
10.2.67	Fourth Amendment to the Mirant Corporation Deferred Compensation Plan for Directors and Select Employees, effective at December 8, 2005 (Incorporated herein by reference to Exhibit 10.22 to the Mirant Corporation Annual Report on Form 10-K filed March 14, 2006, File No. 001-16107)
10.2.68	Mirant Services Severance Pay Plan (as amended and restated effective at July 1, 2008) (Incorporated herein by reference to Exhibit 10.43 to the Mirant Corporation Annual Report on Form 10-K filed February 26, 2010)
10.2.69	First Amendment to the Mirant Services Severance Pay Plan (Incorporated herein by reference to Exhibit 10.44 to the Mirant Corporation Annual Report on Form 10-K filed February 26, 2010)
10.2.70	First Amendment to the Second Amended and Restated Mirant Services Supplemental Executive Retirement Plan (Incorporated herein by reference to Exhibit 10.45 to the Mirant Corporation Annual Report on Form 10-K filed February 26, 2010)
10.2.71	First Amendment to the Mirant Services Supplemental Benefit (Pension) Plan (Incorporated herein by reference to Exhibit 10.46 to the Mirant Corporation Annual Report on Form 10-K filed February 26, 2010)
10.2.72	

Mirant Corporation Change In Control Severance Plan (Incorporated herein by reference to Exhibit 10.47 to the Mirant Corporation Annual Report on Form 10-K filed February 26, 2010)

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Exhibit No.	Exhibit Name
10.2.73	GenOn Energy, Inc. 2010 Non-Employee Directors Compensation Plan, effective at December 3, 2010 (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Current Report on Form 8-K filed December 7, 2010)
10.2.74	Amended and Restated Mirant Services Severance Pay Plan, as amended on April 1, 2010 (Incorporated herein by reference to the Mirant Corporation Quarterly Report on Form 10-Q filed August 6, 2010)
10.2.75	Employment Agreement between Edward R. Muller and RRI Energy, Inc., dated at April 11, 2010 (Incorporated herein by reference to Exhibit 10.1 to the Registrant s Registration Statement on Form S-4, File No. 333-167192)
10.2.76	Offer Letter of Employment Agreement between Mirant Corporation and Anne M. Cleary, dated at April 11, 2010 (Incorporated herein by reference to Exhibit 10.4 to the Registrant s Registration Statement on Form S-4, File No. 333-167192)
10.2.77	Offer Letter of Employment Agreement between Mirant Corporation and Robert Gaudette, dated at April 11, 2010 (Incorporated herein by reference to Exhibit 10.6 to the Registrant s Registration Statement on Form S-4, File No. 333-167192)
10.2.78	Offer Letter of Employment Agreement between Mirant Corporation and J. William Holden, III, dated at April 11, 2010 (Incorporated herein by reference to Exhibit 10.7 to the Registrant s Registration Statement on Form S-4, File No. 333-167192)
10.2.79	GenOn Energy, Inc. 2010 Omnibus Incentive Plan (Incorporated herein by reference to the Registrant s Registration Statement on Form S-8, filed December 3, 2010, Registration No. 333-170952)
10.2.80*	Omnibus Amendment to Registrant s Executive Deferral, Incentive and Non-Qualified Plans effective at December 3, 2010 (amending plans filed as Exhibits 10.2.2, 10.2.3, 10.2.4, 10.2.6, 10.2.8, 10.2.9, 10.2.10, 10.2.13 and 10.2.14)
10.2.81*	Registrant s Deferral and Restoration Plan, as amended and restated effective at January 1, 2011 (amending plan filed as Exhibit 10.2.12)
10.2.82*	Termination Amendment to Registrant s 2002 Stock Plan effective at December 3, 2010 (amending plan filed as Exhibit 10.2.2)
10.2.83*	Termination Amendment to Registrant s 2002 Long-Term Incentive Plan effective at December 3, 2010 (amending plan filed as Exhibit 10.2.8)
10.2.84*	Termination Amendment to Registrant s Transition Stock Plan effective at December 3, 2010 (amending plan filed as Exhibit 10.2.1)
10.2.85*	Termination Amendment Registrant s Long-Term Incentive Plan effective at December 3, 2010 (amending plan filed as Exhibit 10.2.7)
10.2.86*	Second Amendment to the Mirant Services Supplemental Benefit (Pension) Plan effective at January 1, 2010 (amending plan filed as Exhibit 10.2.62)
10.2.87*	Second Amendment to the Second Amended and Restated Mirant Services Supplemental Executive Retirement Plan effective at January 1, 2010 (amending plan filed as Exhibit 10.2.70)
10.2.88*	Termination Amendment to Mirant Services Supplemental Benefit (Savings) Plan effective at December 31, 2010 (amending plan filed as Exhibit 10.2.61)
10.2.89*	Retention Agreement between GenOn Energy, Inc. and Thomas C. Livengood, dated February 7, 2011
10.3.1	Facility Lease Agreement between Conemaugh Lessor Genco LLC and Reliant Energy Mid-Atlantic Power Holdings, LLC, dated at August 24, 2000 (Incorporated herein by reference to Exhibit 4.6a to the RRI Energy Mid-Atlantic Power Holdings, LLC Registration Statement on Form S-4, Registration No. 333-51464)
10.3.2	

Schedule identifying substantially identical agreements to Facility Lease Agreement constituting Exhibit 10.3.1 (Incorporated herein by reference to Exhibit 4.6b to the RRI Energy Mid-Atlantic Power Holdings, LLC Registration Statement on Form S-4, Registration No. 333-51464)

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Exhibit No.	Exhibit Name
10.3.3	Lease Indenture of Trust, Mortgage and Security Agreement between Conemaugh Lessor Genco LLC, as Owner Lessor, and Bankers Trust Company, as Lease Indenture Trustee, dated at August 24, 2000 (Incorporated herein by reference to Exhibit 4.8a to the RRI Energy Mid-Atlantic Power Holdings, LLC Registration Statement on Form S-4, Registration No. 333-51464)
10.3.4	Schedule identifying substantially identical agreements to Lease Indenture of Trust constituting Exhibit 10.3.3 (Incorporated herein by reference to Exhibit 4.8b to the RRI Energy Mid-Atlantic Power Holdings, LLC Registration Statement on Form S-4, Registration No. 333-51464)
10.3.5(a)	Facility Site Lease Agreement and Easement Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Dickerson OL1 LLC and Southern Energy MD Ash Management, LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.5(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.5(b)	Schedule identifying substantially identical agreements to Facility Site Lease Agreement constituting Exhibit 10.3.12(a) (Incorporated herein by reference to Exhibit 10.5(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.6(a)	Facility Site Lease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Morgantown OL1 LLC and Southern Energy MD Ash Management, LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.6(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.6(b)	Schedule identifying substantially identical agreements to Facility Site Lease Agreement constituting Exhibit 10.3.13(a) (Incorporated herein by reference to Exhibit 10.6(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.7(a)	Facility Site Sublease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Dickerson OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.7(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.7(b)	Schedule identifying substantially identical agreements to Facility Site Sublease Agreement constituting Exhibit 10.3.14(a) (Incorporated herein by reference to Exhibit 10.7b to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.8(a)	Facility Site Sublease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Morgantown OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.8a to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.8(b)	Schedule identifying substantially identical agreements to Facility Site Sublease Agreement constituting Exhibit 10.3.15(a) (Incorporated herein by reference to Exhibit 10.8(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.9(a)	Shared Facilities Agreement between Southern Energy Mid-Atlantic, LLC, Dickerson OL1 LLC, Dickerson OL2 LLC, Dickerson OL3 LLC, and Dickerson OL4 LLC, dated at December 18, 2000 (Incorporated herein by reference to Exhibit 10.15a to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.9(b)	Shared Facilities Agreement between Southern Energy Mid-Atlantic, LLC, Morgantown OL1 LLC, Morgantown OL2 LLC, Morgantown OL3 LLC, Morgantown OL4 LLC, Morgantown OL5 LLC, Morgantown OL6 LLC, and Morgantown OL7 LLC, dated at December 18, 2000 (Incorporated herein by reference to Exhibit 10.15(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.10(a)	Assignment and Assumption Agreement between Southern Energy Mid-Atlantic, LLC, Dickerson OL1 LLC, Dickerson OL2 LLC, Dickerson OL3 LLC, and Dickerson OL4 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.16(a) to the Mirant Mid-Atlantic,

LLC Registration Statement on Form S-4, Registration No. 333-61668)

Exhibit No.	Exhibit Name
10.3.10(b)	Assignment and Assumption Agreement between Southern Energy Mid-Atlantic, LLC, Morgantown OL1 LLC, Morgantown OL2 LLC, Morgantown OL3 LLC, Morgantown OL4 LLC, Morgantown OL5 LLC, Morgantown OL6 LLC, and Morgantown OL7 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.16(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.11(a)	Ownership and Operation Agreement between Dickerson OL1 LLC, Dickerson OL2 LLC, Dickerson OL3 LLC, Dickerson OL4 LLC, and Southern Energy Mid-Atlantic, LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.17(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.11(b)	Ownership and Operation Agreement between Morgantown OL1 LLC, Morgantown OL2 LLC, Morgantown OL3 LLC, Morgantown OL4 LLC, Morgantown OL5 LLC, Morgantown OL6 LLC, Morgantown OL7 LLC, and Southern Energy Mid-Atlantic, LLC, dated at December 18, 2000 (Incorporated herein by reference to Exhibit 10.17(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.12(a)	Facility Site Lease Agreement and Easement Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Dickerson OL1 LLC and Southern Energy MD Ash Management, LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.5(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.12(b)	Schedule identifying substantially identical agreements to Facility Site Lease Agreement constituting Exhibit 10.3.12(a) (Incorporated herein by reference to Exhibit 10.5(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.13(a)	Facility Site Lease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Morgantown OL1 LLC and Southern Energy MD Ash Management, LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.6(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.13(b)	Schedule identifying substantially identical agreements to Facility Site Lease Agreement constituting Exhibit 10.3.13(a) (Incorporated herein by reference to Exhibit 10.6(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.14(a)	Facility Site Sublease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Dickerson OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.7(a) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.14(b)	Schedule identifying substantially identical agreements to Facility Site Sublease Agreement constituting Exhibit 10.3.14(a) (Incorporated herein by reference to Exhibit 10.7b to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.15(a)	Facility Site Sublease Agreement (L1) between Southern Energy Mid-Atlantic, LLC, Morgantown OL1 LLC, dated at December 19, 2000 (Incorporated herein by reference to Exhibit 10.8a to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.3.15(b)	Schedule identifying substantially identical agreements to Facility Site Sublease Agreement constituting Exhibit 10.3.15(a) (Incorporated herein by reference to Exhibit 10.8(b) to the Mirant Mid-Atlantic, LLC Registration Statement on Form S-4, Registration No. 333-61668)
10.4.1	Agreement Regarding Prosecution of Litigation by and among Merrill Lynch Commodities, Inc., Merrill Lynch & Co., Inc., Reliant Energy Power Supply, LLC, RERH Holdings, LLC, Reliant Energy Retail Holdings, LLC, Reliant Energy Retail Services, LLC, RE Retail Receivables, LLC and Reliant Energy Solutions East, LLC, dated at February 28, 2009 (Incorporated herein by reference to Exhibit 10.85 to the Registrant s Annual Report on Form 10-K filed March 2, 2009)

10.4.2	Engineering, Procurement and Construction Agreement, dated at July 30, 2007, between Mirant Mid-Atlantic, LLC, Mirant Chalk Point, LLC and Stone & Webster, Inc. (Incorporated herein by reference to Exhibit 10.1 to the Mirant Corporation Quarterly Report on Form 10-Q filed November 6, 2009)

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Exhibit No.	Exhibit Name
10.4.3	Settlement Agreement and Release by and between Mirant Corporation and PEPCO, dated at May 30, 2006 (Incorporated herein by reference to Exhibit 10.1 to the Mirant Corporation Current Report on Form 8-K filed May 31, 2006)
10.4.4	Engineering, Procurement and Construction Agreement between Mirant Marsh Landing, LLC and Kiewit Power Constructors Co., dated at May 6, 2010 (Incorporated herein by reference to Exhibit 10.1 to the Mirant Corporation Quarterly Report on Form 10-Q filed August 6, 2010)
21.1*	Subsidiaries of Registrant
23.1*	Consent of KPMG LLP, dated at March 1, 2011
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under Securities Exchange Act of 1934
32.1*	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(b))
32.2*	Certification of the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(b))
101*	The following financial statements from the Registrant s Annual Report on Form 10 K for the year ended December 31, 2010, filed on March 1, 2011, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Stockholder s Equity and Comprehensive Income (Loss), (iv) the Consolidated Statements of Cash Flows, (v) notes to Consolidated Financial Statements, tagged as blocks of text and (vi) Financial Statement Schedules, tagged as blocks of text.

* Asterisk indicates exhibits filed herewith.

The Registrant has requested confidential treatment for certain portions of this Exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GenOn Energy, Inc.

By:
/s/ Edward R. Muller

Edward R. Muller
Chairman of the Board and Chief Executive Officer

Date: March 1, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	
/s/ Edward R. Muller **Edward R. Muller**	**Chairman of the Board and Chief Executive Officer (Principal Executive Officer)**	Date: March 1, 2011
/s/ J. William Holden, III **J. William Holden, III**	**Executive Vice President and Chief Financial Officer (Principal Financial Officer)**	Date: March 1, 2011
/s/ Thomas C. Livengood **Thomas C. Livengood**	**Senior Vice President and Controller (Principal Accounting Officer)**	Date: March 1, 2011
/s/ E. William Barnett **E. William Barnett**	**Director**	Date: March 1, 2011
/s/ Terry G. Dallas **Terry G. Dallas**	**Director**	Date: March 1, 2011
/s/ Mark M. Jacobs **Mark M. Jacobs**	**Director**	Date: March 1, 2011
/s/ Thomas H. Johnson **Thomas H. Johnson**	**Director**	Date: March 1, 2011

/s/ Steven L. Miller	**Director**	Date: March 1, 2011
Steven L. Miller		
/s/ Robert C. Murray	**Director**	Date: March 1, 2011
Robert C. Murray		

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Signatures	Title	
/s/ Laree E. Perez	**Director**	Date: March 1, 2011
Laree E. Perez		
/s/ Evan J. Silverstein	**Director**	Date: March 1, 2011
Evan J. Silverstein		
/s/ William L. Thacker	**Director**	Date: March 1, 2011
William L. Thacker		