GenOn Energy, Inc.
Form 10-Q
May 09, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2011

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

(832) 357-3000

(Registrant s Telephone Number, Including Area Code)

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. þ Yes o No

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). þ Yes o No

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.

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 Exchange Act). o Yes þ No

As of May 2, 2011, there were 771,484,710 shares of the registrant s Common Stock, $0.001 par value per share, outstanding.

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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, spinning and non-spinning 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.
CFTC	Commodity Futures Trading Commission.
Clean Air Act	Federal Clean Air Act.
Clean Water Act	Federal Water Pollution Control Act.
CO_2	Carbon dioxide.
dark spread	The difference between power prices and coal fuel costs.
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.
FERC	Federal Energy Regulatory Commission.
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 credit facilities	Senior secured term loan and revolving credit facility of GenOn and certain of its subsidiaries.
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 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 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).
HAP	Hazardous Air Pollutant.
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.
MACT	Maximum achievable control technology.
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 Standards.
net generating capacity	Net summer capacity.
NOL	Net operating loss.

NOV	Notice of violation.
NO_x	Nitrogen oxides.
NPDES	National pollutant discharge elimination system.
NYISO	New York Independent System Operator.
NYMEX	New York Mercantile Exchange.
OTC	Over-the-counter.
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.
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.
REMA	GenOn REMA, LLC and its subsidiaries (formerly known as RRI Energy Mid-Atlantic Power Holdings, LLC).
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.
scrubbers	Flue gas desulfurization emissions controls.
SEC	United States Securities and Exchange Commission.
Securities Act	Securities Act of 1933, as amended.

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.
Stone & Webster	Stone & Webster, Inc.
Total margin capture factor	Represents the percentage of actual energy, contracted and capacity gross margin generated of the potential energy, contracted and capacity gross margin that could have been generated for a unit.
Transport Rule	The EPA s Proposed Federal Implementation Plan To Reduce Interstate Transport of Fine Particulate Matter and Ozone, which would replace the CAIR.
VaR	Value at risk.
VIE	Variable interest entity.
Virginia DEQ	Virginia Department of Environmental Quality.
WCI	Western Climate Initiative.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act 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, inte anticipate, estimate, predict, target, potential or continue or the negative of these terms or other comparable 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 fuel;
- 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 beyond collateral posted or to perform obligations or services due to us;
- 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 arrangements for sales of capacity, energy and other products from our existing generating facilities;

our ability to execute our plan in respect of our Marsh Landing generating facility, including obtaining and maintaining the governmental authorizations 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;

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 pending rulemaking proceedings), 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) that restrict our ability or render it uneconomic to operate our assets, including regulations 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 existing 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;

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 contained herein 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.

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 Management s Discussion and Analysis of Financial Condition and Results of Operations and the accompanying notes to GenOn s interim financial statements, other factors that could affect our future performance are set forth in our 2010 Annual Report on Form 10-K.

Certain Terms

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

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PART I
FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
GENON ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended March 31, 2011	2010
	(in millions, except per share data) (See notes 1 and 2 on the Merger)	
Operating revenues (including unrealized gains (losses) of $(99) million and $363 million, respectively)	$ 814	$ 880
Cost of fuel, electricity and other products (including unrealized (gains) losses of $(20) million and $11 million, respectively)	404	207
Gross Margin (excluding depreciation and amortization)	410	673
Operating Expenses:		
Operations and maintenance	304	166
Depreciation and amortization	86	51
Gain on sales of assets, net	(1)	(2)
Total operating expenses	389	215
Operating Income	21	458
Other Income (Expense), net:		
Interest expense	(109)	(50)
Other, net	(22)	(1)
Total other expense, net	(131)	(51)
Income (Loss) Before Income Taxes	(110)	407
Provision for income taxes	3	
Net Income (Loss)	$ (113)	$ 407
Basic and Diluted EPS:		
Basic EPS	$ (0.15)	$ 0.99
Diluted EPS	$ (0.15)	$ 0.99
Weighted average shares outstanding	771	412
Effect of dilutive securities		1
Weighted average shares outstanding assuming dilution	771	413

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2011	December 31, 2010
	(in millions) (See notes 1 and 2 on the Merger)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,390	$ 2,402
Funds on deposit	811	1,834
Receivables, net	293	536
Derivative contract assets	1,016	1,420
Inventories	508	554
Prepaid expenses and other current assets	137	155
Total current assets	5,155	6,901
Property, plant and equipment, gross	7,338	7,275
Accumulated depreciation and amortization	(1,046)	(977)
Property, Plant and Equipment, net	6,292	6,298
Noncurrent Assets:		
Intangible assets, net	136	144
Derivative contract assets	621	716
Deferred income taxes	427	362
Prepaid rent	324	348
Other	535	505
Total noncurrent assets	2,043	2,075
Total Assets	$ 13,490	$ 15,274
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 924	$ 2,058
Accounts payable and accrued liabilities	714	902
Derivative contract liabilities	860	1,227
Deferred income taxes	427	362
Other	130	133
Total current liabilities	3,055	4,682
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,022	4,023
Derivative contract liabilities	140	189
Pension and postretirement obligations	172	171

Other		577		579
Total noncurrent liabilities		4,911		4,962
Commitments and Contingencies				
Stockholders Equity:				
Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at March 31, 2011 and December 31, 2010				
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 771,243,978 shares and 770,857,530 shares at March 31, 2011 and December 31, 2010, respectively		1		1
Additional paid-in capital		7,437		7,432
Accumulated deficit		(1,891)		(1,778)
Accumulated other comprehensive loss		(23)		(25)
Total stockholders equity		5,524		5,630
Total Liabilities and Stockholders Equity	$	13,490	$	15,274

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE LOSS (UNAUDITED)

	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total Stockholders Equity
			(in millions) (See notes 1 and 2 on the Merger)		
Balance, December 31, 2010	$ 1	$ 7,432	$ (1,778)	$ (25)	$ 5,630
Stock-based compensation		4			4
Exercise of stock options		1			1
Total stockholders equity before other comprehensive loss	1	7,437	(1,778)	(25)	5,635
Net loss			(113)		(113)
Change in fair value of available-for-sale securities, net of tax of $0				(1)	(1)
Change in fair value of qualifying derivatives, net of settlements, net of tax of $0				3	3
Total other comprehensive loss					(111)
Balance, March 31, 2011	$ 1	$ 7,437	$ (1,891)	$ (23)	$ 5,524

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31, 2011	2010
	(in millions) (See notes 1 and 2 on the Merger)	
Cash Flows from Operating Activities:		
Net income (loss)	$ (113)	$ 407
Adjustments to reconcile net income (loss) and changes in other operating assets and liabilities to net cash provided by operating activities:		
Depreciation and amortization	90	52
Amortization of acquired contracts	(5)	
Gain on sales of assets, net	(1)	(2)
Net changes in derivative contracts	79	(352)
Stock-based compensation expense	3	5
Lower of cost or market inventory adjustments		8
Loss on extinguishment of debt	24	
Funds on deposit	(42)	(14)
Changes in other operating assets and liabilities	183	198
Total adjustments	331	(105)
Net cash provided by operating activities of continuing operations	218	302
Net cash provided by operating activities of discontinued operations		2
Net cash provided by operating activities	218	304
Cash Flows from Investing Activities:		
Capital expenditures	(98)	(85)
Proceeds from the sales of assets	1	2
Restricted funds on deposit, net	1,020	
Net cash provided by (used in) investing activities	923	(83)
Cash Flows from Financing Activities:		
Repayment of long-term debt	(1,153)	(67)
Other		(2)
Net cash used in financing activities	(1,153)	(69)
Net Increase (Decrease) in Cash and Cash Equivalents	(12)	152
Cash and Cash Equivalents, beginning of period	2,402	1,953
Cash and Cash Equivalents, end of period	$ 2,390	$ 2,105

Supplemental Disclosures:				
Cash paid for interest, net of amounts capitalized	$	16	$	2
Cash paid for income taxes (net of refunds received)	$	(5)	$	

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements

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GENON ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Description of Business and Accounting and Reporting Policies

Background

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.

We were formed as a Delaware corporation in August 2000. GenOn changed its name from RRI Energy, Inc. effective December 3, 2010 in connection with the Merger. We, us, our and GenOn refer 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. See note 2 for additional information on the Merger.

Basis of Presentation

The consolidated interim financial statements and notes (interim financial statements) are unaudited, omit certain disclosures and should be read in conjunction with our audited consolidated financial statements and notes in our 2010 Annual Report on Form 10-K. These interim financial statements have been prepared in accordance with GAAP from records maintained by us. All significant intercompany accounts and transactions have been eliminated in consolidation. The interim financial statements reflect all normal recurring adjustments necessary, in management s opinion, to present fairly our financial position and results of operations for the reported periods. Amounts reported for interim periods may not be indicative of a full year period because of seasonal fluctuations in demand for electricity and energy services, changes in commodity prices, and changes in regulations, timing of maintenance and other expenditures, dispositions, changes in interest expense and other factors.

In connection with the Merger, former Mirant stockholders received approximately 54% of the voting interest in the combined company. Although RRI Energy was the legal acquirer, the Merger is accounted for as a reverse acquisition whereby Mirant is treated as the accounting acquirer and RRI Energy is treated as the acquired company for financial reporting purposes. As such, the interim 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 interim financial statements and other financial information of Mirant.

At March 31, 2011, substantially all of our subsidiaries are wholly-owned and located in the United States. We do not consolidate five power generating facilities which are under operating leases; a 50% equity investment in a cogeneration facility; and a VIE (MC Asset Recovery) for which we are not the primary beneficiary. See note 11 for further discussion of MC Asset Recovery.

The preparation of interim 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 interim financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. Our 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 the deferred tax asset valuation allowance;
- estimating the useful lives of long-lived assets;
- estimating future costs and the valuation 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.

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We evaluate events that occur after the balance sheet date but before the financial statements are issued for potential recognition or disclosure. Based on the evaluation, we determined that there were no material subsequent events for recognition or disclosure other than those disclosed herein.

Funds on Deposit

Funds on deposit are included in current and noncurrent assets in the consolidated balance sheets. Funds on deposit include the following:

	March 31, 2011	December 31, 2010
	(in millions)	
Funds deposited with the trustee to defease the PEDFA fixed-rate bonds, due 2036[1]	$ 394	$ 394
Cash collateral posted[2]	297	299
GenOn Marsh Landing development project cash collateral posted[3]	152	106
GenOn Mid-Atlantic restricted cash[4]	143	
Environmental compliance deposits[5]	32	32
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
Other	26	40
Total current and noncurrent funds on deposit	1,044	2,022
Less: Current funds on deposit	811	1,834
Total noncurrent funds on deposit	$ 233	$ 188

(1) See note 5 for discussion of the related debt.

(2) Represents cash collateral posted for energy trading and marketing and other operating activities; includes $32 million related to the Potomac River Settlement (see note 19 to our consolidated financial statements in our 2010 Annual Report on Form 10-K); includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at March 31, 2011 and December 31, 2010.

(3) Represents cash-collateralized letters of credit to support the Marsh Landing development project.

(4) Represents cash reserved in respect of interlocutory liens related to the scrubber contract litigation. See note 11.

(5) Represents deposits with the State of Pennsylvania to guarantee our obligations related to future closures of coal ash landfill sites and with the State of New Jersey to satisfy our obligations under the Industrial Site Recovery Act. See note 11 for our obligations related to ash landfill sites and site contamination remediation.

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Inventories

Inventories were comprised of the following:

	March 31, 2011	December 31, 2010
	(in millions)	
Fuel inventory:		
Coal	$ 170	$ 153
Fuel oil	108	170
Natural gas		1
Other	2	1
Materials and supplies	197	194
Purchased emissions allowances	31	35
Total inventories	$ 508	$ 554

During the three months ended March 31, 2011 and 2010, we recorded $0 and $8 million, respectively, for lower of average cost or market valuation adjustments in cost of fuel, electricity and other products.

Capitalization of Interest Cost

We incurred the following interest costs:

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Total interest costs	$ 111	$ 52
Capitalized and included in property, plant and equipment, net	(2)	(2)
Interest expense	$ 109	$ 50

The amounts of capitalized interest above include interest accrued. During the three months ended March 31, 2011 and 2010, cash paid for interest was $17 million and $2 million, respectively, of which $1 million and $0, respectively, were capitalized.

Income Taxes

At March 31, 2011, our deferred tax assets, as reduced by the valuation allowance, are completely offset by our deferred tax liabilities. 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 have evaluated the evidence at March 31, 2011 and based on our judgment have determined that it is more-likely-than-not (greater than a 50% probability) that the net deferred tax assets will not be realized.

Recently Adopted Accounting Guidance

We adopted FASB accounting guidance for the quarter ended March 31, 2011 that requires a reconciliation for Level 3 fair value measurements, including presenting separately the amounts of purchases, issuances and settlements on a gross basis. See note 4 for additional information on fair value measurements.

2. Merger

On December 3, 2010, Mirant and RRI Energy completed the Merger. The Merger is accounted for under the acquisition method of accounting for business combinations. Accordingly, we have 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. 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. The significant assets and liabilities for which provisional amounts are recognized at March 31, 2011 and December 31, 2010 are property, plant and equipment, intangible assets and long-term liabilities related to out-of-market contracts, contingencies, taxes 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. We will finalize these amounts during 2011.

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3. Merger-Related Costs

Changes in merger-related costs (recorded in operations and maintenance expense in the Other Operations segment) are as follows (in millions):

Balance, January 1, 2011	$	30(1)
Accrued and expensed		23(2)
Paid		(32)
Balance, March 31, 2011	$	21(1)

(1) Included in accounts payable and accrued liabilities in the applicable consolidated balance sheet.

(2) Includes $17 million of charges associated with employee severance and $6 million of charges related to integration and other activities.

4. Financial Instruments

Derivatives and Hedging Activities.

In connection with the 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 fuel inventories. We through our asset management activities 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 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 physical fuel oil inventories, optimize the approximately three million barrels of storage capacity that we own or lease, and attempt to profit from market opportunities related to timing and/or differences in the pricing of various products. The open positions in our trading activities comprising proprietary trading and fuel oil management activities expose us to risks associated with changes in energy commodity prices.

Derivative financial instruments are recorded in the consolidated balance sheets at fair value, except for derivative contracts that qualify for and for which we have elected the normal purchase or normal sale exceptions, which are not reflected in the consolidated balance sheet or results of operations prior to accrual of the settlement. We present our 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 its 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. With the exception of these interest rate swaps, we did not have any other derivative financial instruments designated as fair value or cash flow hedges for accounting purposes during the three months ended March 31, 2011 or during 2010.

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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. We record 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 our results of operations. If it becomes probable that a forecasted transaction will not occur, we immediately recognize the related deferred gains or losses in our 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 our 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. Our 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.

We also consider risks associated with interest rates, counterparty credit and our own non-performance risk when valuing 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 the transactions being valued.

The following table presents the fair value of derivative financial instruments:

	Derivative Contract Assets		Derivative Contract Liabilities		Net Derivative Contract Assets (Liabilities)
	Current	Long-Term	Current	Long-Term	
			(in millions)		
March 31, 2011					
Commodity Contracts:					
Asset management	$ 491	$ 555	$ (312)	$ (91)	$ 643
Trading activities	525	44	(548)	(49)	(28)
Total commodity contracts	1,016	599	(860)	(140)	615
Interest Rate Contracts		22			22
Total derivatives	$ 1,016	$ 621	$ (860)	$ (140)	$ 637
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

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The following table presents the net gains (losses) for derivative financial instruments recognized in income in the unaudited condensed consolidated statements of operations:

	Three Months Ended March 31,			
	2011		2010	
Derivatives Not Designated as Hedging Instruments	Operating Revenues	Cost of Fuel, Electricity and Other Products	Operating Revenues	Cost of Fuel, Electricity and Other Products
	(in millions)			
Asset Management Commodity Contracts:				
Unrealized	$ (75)	$ 20	$ 353	$ (11)
Realized[(1)(2)]	79	(43)	85	(15)
Total asset management	$ 4	$ (23)	$ 438	$ (26)
Trading Commodity Contracts:				
Unrealized	$ (24)	$	$ 10	$
Realized[(1)(2)]	6		19	
Total trading	$ (18)	$	$ 29	$
Total derivatives	$ (14)	$ (23)	$ 467	$ (26)

(1) Represents the total cash settlements of derivative financial instruments during each quarterly reporting period that existed at the beginning of each respective period.

(2) Effective January 1, 2011, excludes settlement value of fuel contracts classified as inventory.

The following table presents the effect of the interest rate swaps designated as cash flow hedges in the unaudited consolidated statements of stockholders equity and comprehensive income/loss during the three months ended March 31, 2011 (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)		
$24	Interest expense	$	$

(1) Represents the ineffective portion of the interest rate swaps classified as cash flow hedges. The assessment of effectiveness excludes the default risk of the counterparties to these transactions and our own non-performance risk. The effect of these valuation adjustments was a loss of an immaterial amount during the three months ended March 31, 2011 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 our results of operations as a result of discontinued cash flow hedges.

At March 31, 2011, the maximum length of time we are hedging our exposure to the variability in future cash flows that may result from changes in interest rates is 12 years. Because a significant portion of the interest expense incurred by GenOn Marsh Landing during construction will be capitalized, amounts included in accumulated other comprehensive loss associated with construction period interest payments 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. Actual amounts reclassified into earnings could vary from the amounts currently recorded as a result of future changes in interest rates.

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The following tables present the notional quantity on long (short) positions for derivative financial instruments:

Derivative Instruments	Notional Volumes at March 31, 2011 Derivative Contract Assets	Derivative Contract Liabilities (in millions)	Net Derivative Contracts
Commodity Contracts (in equivalent MWh):			
Power[1]	(27)	(24)	(51)
Natural gas	(13)	14	1
Fuel oil	2	(2)	
Coal	8	9	17
Interest Rate Contracts (in dollars)[2]	475		475

Derivative Instruments	Notional Volumes at December 31, 2010 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

(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.

Fair Value Measurements.

Fair Value Hierarchy and Valuation Techniques. We apply recurring fair value measurements to our financial assets and liabilities. 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 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 financial assets and liabilities carried at fair value in the 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 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 interest rate swaps.

Level 3: This category includes the commodity 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 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, power transmission 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. Our 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 our derivative contract assets and liabilities is based largely on observable quoted prices from exchanges and indicative quoted prices from independent brokers in active markets that 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 derivative contract assets and liabilities, we use third-party market pricing where available. For transactions classified in Level 1 of the fair value hierarchy, we use the unadjusted published settled prices on the valuation date. For transactions classified in Level 2 of the fair value hierarchy, 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 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 as of the valuation date that extend for the tenor of the underlying contracts for each delivery location. 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 monthly. The validation procedures include reviewing the quotes for accuracy and comparing them to our internal price curves. In certain instances, we may exclude from consideration a broker quote if it is a clear outlier and other quotes are obtained. As of March 31, 2011, 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 derivative contract assets and liabilities that may be structured or otherwise 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 March 31, 2011, the assets and liabilities classified as Level 3 in the fair value hierarchy represented approximately 3% of total assets and 10% of total liabilities measured at fair value.

The fair value of our derivative contract assets and liabilities is also affected by assumptions as to time value, credit risk and non-performance risk. The nominal value of 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 us. The counterparty default risk for our overall net position is measured based on published spreads on credit default swaps for counterparties, where available, or proxies based upon published spreads, applied to our current exposure and potential loss exposure from the financial commitments in our risk management portfolio. The fair value of derivative contract liabilities is reduced to reflect the estimated risk of default on contractual obligations to counterparties and is measured based on published default rates of our debt, where available, or proxies based upon published spreads. Credit risk and non-performance risk 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.

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Fair Value of Derivative Instruments and Certain Other Assets. The fair value measurements of financial assets and liabilities by class are as follows:

	March 31, 2011			
	Level 1[1]	Level 2[1][2]	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 5	$ 995	$ 9	$ 1,009
Fuel	2	2	33	37
Total Asset Management	7	997	42	1,046
Trading Activities	257	300	12	569
Interest Rate Contracts		22		22
Total derivative contract assets	$ 264	$ 1,319	$ 54	$ 1,637
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 10	$ 287	$ 4	$ 301
Fuel	13		89	102
Total Asset Management	23	287	93	403
Trading Activities	262	326	9	597
Interest Rate Contracts				
Total derivative contract liabilities	$ 285	$ 613	$ 102	$ 1,000
Interest-bearing funds[3]	$ 3,131	$	$	$ 3,131
Other assets[4]	$ 34	$	$	$ 34

(1) Transfers between Level 1 and Level 2 are recognized as of the end of the reporting period. There were no significant transfers during the three months ended March 31, 2011.

(2) Option contracts comprised approximately 5% of net derivative contract assets.

(3) Represents 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. We had $2.353 billion of interest-bearing funds included in cash and cash equivalents, $558 million included in funds on deposit and $220 million included in other noncurrent assets.

(4) Includes $12 million in available-for-sale securities (shares in a publicly traded exchange) and $22 million in trading securities (rabbi trust investments (comprised of mutual funds) associated with our non-qualified deferred

compensation plans for some key and highly compensated employees).

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	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 approximately 7% of net derivative contract assets.

(3) Represents 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. We 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) Includes $13 million in available-for-sale securities (shares in a publicly traded exchange) and $18 million in trading securities (rabbi trust investments (comprised of mutual funds) associated with our non-qualified deferred compensation plans for some key and highly compensated employees).

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The following is a reconciliation of changes in fair value of net commodity derivative contract assets and liabilities classified as Level 3 during the three months ended March 31, 2011 and 2010, respectively:

	Net Derivatives Contracts (Level 3)		
	Asset Management	Trading Activities	Total
		(in millions)	
Balance, January 1, 2011 (net asset (liability))	$ (70)	$ 2	$ (68)
Total gains (losses) realized/unrealized:			
Included in earnings [(1)]	23	1	24
Purchases[(2)]			
Issuances[(2)]			
Settlements[(3)]	(4)		(4)
Transfers in and out of Level 3[(4)]			
Balance, March 31, 2011 (net asset (liability))	$ (51)	$ 3	$ (48)
Balance, January 1, 2010 (net asset (liability))	$ 19	$ 13	$ 32
Total gains (losses) realized/unrealized:			
Included in earnings [(1)]	(11)	21	10
Purchases[(2)]			
Issuances[(2)]			
Settlements[(5)]	(13)	10	(3)
Transfers in and out of Level 3[(4)]	37		37
Balance, March 31, 2010 (net asset (liability))	$ 32	$ 44	$ 76

(1) Represents the fair value, as of the end of each quarterly reporting period, of Level 3 contracts entered into during each quarterly reporting period and the gains and losses attributable to Level 3 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) Contracts entered into during each quarterly reporting period are reported with other changes in fair value.

(3) Effective January 1, 2011, represents the reversal of previously recognized unrealized gains and losses from settlement of contracts during each quarterly reporting period.

(4) 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.

(5) Represents the total cash settlements of contracts during each quarterly reporting period that existed at the beginning 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:

	Three Months Ended March 31,					
	2011			2010		
	Operating Revenues	Cost of Fuel, Electricity and Other Products	Total	Operating Revenues	Cost of Fuel, Electricity and Other Products	Total
	(in millions)					
Gains (losses) included in income	$ 4	$ 16	$ 20	$ 38	$ 6	$ 44
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 March 31	$ 4	$ 15	$ 19	$ 38	$ 6	$ 44

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Counterparty Credit Concentration Risk.
We are exposed to the default risk of the counterparties with which we transact. We manage our 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. We also have 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. Our credit reserve on derivative contract assets was $15 million and $21 million at March 31, 2011 and December 31, 2010, respectively.
At March 31, 2011 and December 31, 2010, $2 million and $3 million, respectively, of cash collateral posted to us by counterparties under master netting agreements were included in accounts payable and accrued liabilities on the consolidated balance sheets.
We also monitor 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:

	March 31, 2011				
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	$ 696	$ 35	$ 35	$	
Investment Grade:					
Financial institutions	765	680		680	70%
Energy companies	401	217	8	209	22%
Other	1	1		1	
Non-investment Grade:					
Energy companies	22	14		14	1%
No External Ratings:					
Internally-rated investment grade	42	41		41	4%
Internally-rated non-investment grade	28	28		28	3%
Total	$ 1,955	$ 1,016	$ 43	$ 973	100%

	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%

Non-investment Grade:					
Energy companies	31	18		18	2%
No External Ratings:					
Internally-rated investment grade	52	45		45	4%
Internally-rated non-investment grade	34	34	8	26	2%
Total	$ 2,582	$ 1,199	$ 84	$ 1,115	100%

(1) Gross exposure before collateral represents credit exposure, including both 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 with counterparties and netting of transactions with clearing brokers and exchanges.

(3) Collateral includes cash and letters of credit received from counterparties.

We had credit exposure to two investment grade counterparties at March 31, 2011 and three investment grade counterparties at December 31, 2010, each representing an exposure of more than 10% of total credit exposure, net of collateral and totaling $536 million and $716 million at March 31, 2011 and December 31, 2010, respectively.

GenOn Credit Risk.

Our standard industry contracts contain credit-risk-related contingent features such as ratings-related thresholds whereby we 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 our contracts contain language, which is generally subjective in nature that could require us to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. However, as a result of our current credit rating, we are typically required to post collateral in the normal course of business to offset either substantially or completely the net liability positions, after applying the terms of master netting agreements. At March 31, 2011, the fair value of financial instruments with credit-risk-related contingent features in a net liability position was $37 million for which we had posted collateral of $26 million, including cash and letters of credit.

At March 31, 2011 and December 31, 2010, we had $93 million and $107 million, respectively, of cash collateral posted with counterparties under master netting agreements that was included in funds on deposit on the consolidated balance sheets.

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 financial instruments are as follows:

	March 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Liabilities:				
Long and short-term debt[1]	$ 4,946	$ 5,040	$ 6,081	$ 6,095

(1) The fair value of long- and short-term debt is estimated using quoted market prices, when available.

5. Long-Term Debt

Outstanding debt was as follows:

	March 31, 2011			December 31, 2010		
	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		7.625	575	
Senior unsecured notes, due 2017	7.875	725		7.875	725	
Senior secured term loan, due 2017(3)	6.00	690	7	6.00	691	7
Senior unsecured notes, due 2018(4)	9.50	675		9.50	675	
Senior unsecured notes, due 2020(4)	9.875	550		9.875	550	
Unamortized debt discounts		(27)	(2)		(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)			(2)	
GenOn North America:						
Senior notes, due 2013(5)				7.375		850
Other:						
Capital leases, due 2011 to 2015	7.375 8.19	17	4	7.375 8.19	18	4
PEDFA fixed-rate bonds, due 2036(6)	6.75		371	6.75		371
Adjustment to fair value of debt(7)		(31)	9		(32)	14
Total		$ 4,022	$ 924		$ 4,023	$ 2,058

(1) The weighted average stated interest rates are at March 31, 2011 and December 31, 2010.

(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 9.75% and 10.2% for senior unsecured notes due 2018 and 2020, respectively.

(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. We expect 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. Included in interest expense is amortization of $1 million for valuation adjustments related to the assumed debt for the three months ended March 31, 2011.

GenOn Credit Facilities

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At March 31, 2011, outstanding letters of credit were $246 million and availability of borrowings under the revolving credit facility was $542 million.

Senior Unsecured Notes, Due 2018 and 2020

In connection with our obligations under the Registration Rights Agreement with the initial purchasers of these senior secured notes, dated October 4, 2010, we filed a registration statement and commenced, in the second quarter of 2011, offerings to exchange the existing notes for a like principal amount at maturity of new notes. The new notes will have the same terms and conditions as the existing notes, including interest rates, maturity dates and covenants. We expect the exchange offerings to be completed in the second quarter of 2011.

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Repayment of Debt:

GenOn Senior Secured Notes Due 2014

The senior secured notes due 2014 (issued in 2004) were recorded at their fair value on the Merger date which approximated their redemption value. Upon the 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 was 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 and $1 million loss on extinguishment of debt was recognized during the three months ended March 31, 2011.

GenOn North America Senior Notes Due 2013

Upon the 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 was 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 (in other, net on the consolidated statement of operations) was recognized during the three months ended March 31, 2011, which includes a $16 million premium and $7 million of unamortized debt issuance costs.

GenOn Americas Generation Senior Notes

On May 2, 2011, GenOn Americas Generation repaid the $535 million of senior notes that came due.

6. Guarantees and Letters of Credit

We generally conduct business through various operating subsidiaries which enter into contracts as part of their business activities. In certain instances, the contractual obligations of such subsidiaries are guaranteed by, or otherwise supported by, us or another of our subsidiaries, including by letters of credit issued under the GenOn credit facilities.

In addition, we, including our 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 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, our 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, we determine 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.

Following is a summary of letters of credit issued and surety bonds provided:

	March 31, 2011	December 31, 2010
	(in millions)	
Letters of credit Marsh Landing development project	$ 152	$ 106
Letters of credit rent reserves	142	133
Letters of credit energy trading and marketing activities	63	96
Letters of credit other operating activities	41	38
Surety bonds[(1)]	47	50
Total	$ 445	$ 423

(1) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at March 31, 2011 and December 31, 2010.

This note should be read in conjunction with note 10 to our consolidated financial statements in our 2010 Annual Report on Form 10-K.

7. Pension and Other Postretirement Benefit Plans

We have various defined benefit and defined contribution pension plans, and other postretirement benefit plans. For a further discussion of these plans, see note 8 to our consolidated financial statements in our 2010 Annual Report on Form 10-K.

Net Periodic Benefit Cost (Credit)

The components of the net periodic benefit cost (credit) are shown below:

	Pension Plans Three Months Ended March 31,		Other Postretirement Benefit Plans Three Months Ended March 31,	
	2011	2010	2011	2010
	(in millions)			
Service cost	$ 3	$ 2	$	$
Interest cost	6	4	1	1
Expected return of plan assets	(8)	(5)		
Net amortization[(1)]	1		(1)	(2)
Net periodic benefit cost (credit)	$ 2	$ 1	$	$ (1)

(1) Net amortization amount includes prior service cost and actuarial gains or losses.

8. Stock-Based Compensation

Compensation expense for the stock-based incentive plans was:

	Three Months Ended March 31,

	2011		2010	
	(in millions)			
Stock-based incentive plans compensation expense (pre-tax) (1)(2)	$	3	$	4

(1) See note 9 to our consolidated financial statements in our 2010 Annual Report on Form 10-K for information about stock-based incentive plans compensation expense.

(2) No tax benefits related to stock-based compensation were realized during the three months ended March 31, 2011 and 2010 because of our NOL carryforwards.

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During February 2011, we granted long-term incentive awards as follows:

Award Vehicle	Awards Granted	Vesting Period
Time-based Restricted Stock Units	2,091,599	Vest ratably each year over a three-year period; settled in common stock
Performance-based Restricted Stock Units	1,810,569	Linked to the 2011 short-term incentive plan performance goals, with performance measured at the end of the first year to determine multiplier; vest ratably each year over three-year period; settled in common stock
Nonqualified Stock Options	4,118,280	Time-based; vested ratably each year over three-year period

9. Earnings Per Share

We calculate basic EPS by dividing income available to stockholders by the weighted average number of common shares outstanding. Diluted EPS gives effect to dilutive potential common shares, including unvested restricted stock units, stock options and warrants. Share amounts below reflect Mirant s historical activity for the three months ended March 31, 2010 retroactively adjusted to give effect to the Exchange Ratio and include the combined entities for the three months ended March 31, 2011.

The following table shows the computation of basic and diluted EPS:

	Three Months Ended March 31, 2011		Three Months Ended March 31, 2010	
	(in millions, except per share data)			
Net income (loss)	$	(113)	$	407
Basic and diluted shares:				
Weighted average shares outstanding basic		771		412
Shares from assumed vesting of restricted stock units		(1)		1
Weighted average shares outstanding diluted		771		413
Basic and Diluted EPS				
Basic EPS	$	(0.15)	$	0.99
Diluted EPS	$	(0.15)	$	0.99

(1) Because we incurred a net loss during this period, diluted loss per share is the same as basic loss per share.

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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 was as follows:

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Series A Warrants[1]		76
Series B Warrants[1]		20
Restricted stock units	3	1
Stock options	19	12
Total number of antidilutive shares	22	109

(1) These warrants expired January 3, 2011.

10. Segment Reporting

In conjunction with the Merger, we began reporting in five segments in the fourth quarter of 2010: Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations. Prior to the Merger, we had four reportable segments: Mid-Atlantic, Northeast, California and Other Operations. Amounts for 2010 were reclassified to conform to the current segment presentation. The segments were determined based on how the business is managed and align with the information provided to the chief operating decision-maker for purposes of assessing performance and allocating resources. Generally, our 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. We also engage in proprietary trading, fuel oil management and natural gas transportation and storage 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.

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 (established as a result of the Merger) 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 seven generating facilities located in California, with total net generating capacity of 5,363 MW and includes business development and construction activities for GenOn Marsh Landing. The total net generating capacity for California excludes the Potrero generating facility of 362 MW, which was shut down on February 28, 2011. 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 Florida, Massachusetts, Mississippi, New York and Texas with total net generating capacity of 5,055 MW. Other Operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment. All revenues are generated and long-lived assets are located within the United States.

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Our measure of profit or loss for the reportable segments is operating income/loss. This measure represents the lowest level of information that is provided to the chief operating decision-maker for the reportable segments.

Operating Segments

	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations[1]	Total
			(in millions)				
Three Months Ended March 31, 2011:							
Operating revenues[2]	$ 316	$ 324	$ 36	$ 85	$ 53	$	$ 814
Cost of fuel, electricity and other products[3]	138	163	2	69	30	2	404
Gross margin (excluding depreciation and amortization)	178	161	34	16	23	(2)	410
Operating Expenses:							
Operations and maintenance	106	110	39	4	45[4]		304
Depreciation and amortization	31	25	14		16		86
Gain on sales of assets, net					(1)		(1)
Total operating expenses	137	135	53	4	60		389
Operating income (loss)	$ 41	$ 26	$ (19)	$ 12	$ (37)	$ (2)	$ 21
Total assets at March 31, 2011	$ 4,725	$ 3,831	$ 723	$ 2,138	$ 5,887[5]	$ (3,814)	$ 13,490

(1) Primarily relates to intercompany sales of emissions allowances.

(2) Includes unrealized losses of $51 million, $24 million, $13 million and $11 million for Eastern PJM, Energy Marketing, Western PJM/MISO and Other Operations, respectively.

(3) Includes unrealized gains of $12 million, $4 million, $2 million and $2 million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.

(4) Includes $23 million of merger-related costs.

(5) Includes our equity method investment in Sabine Cogen, LP of $23 million.

Operating Segments

	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
				(in millions)			
Three Months Ended March 31, 2010:							
Operating revenues[1]	$ 739	$	$ 38	$ 31	$ 72	$	$ 880
Cost of fuel, electricity and other products[2]	155		8		44		207
Gross margin (excluding depreciation and amortization)	584		30	31	28		673
Operating Expenses:							
Operations and maintenance	113		20	2	31		166
Depreciation and amortization	33		8		10		51
Gain on sales of assets, net	(2)						(2)
Total operating expenses	144		28	2	41		215
Operating income (loss)	$ 440	$	$ 2	$ 29	$ (13)	$	$ 458
Total assets at December 31, 2010	$ 4,832	$ 3,846	$ 664	$ 2,771	$ 7,016(3)	$ (3,855)	$ 15,274

(1) Includes unrealized gains of $338 million, $15 million and $10 million for Eastern PJM, Other Operations and Energy Marketing, respectively.

(2) Includes unrealized losses of $19 million for Other Operations and unrealized gains of $8 million for Eastern PJM.

(3) Includes our equity method investment in Sabine Cogen, LP of $23 million.

	Three Months Ended March 31,	
	2011	2010
	(in millions)	

Operating income for all segments	$	21	$	458
Interest expense		(109)		(50)
Other, net		(22)		(1)
Income (loss) before income taxes	$	(110)	$	407

11. Litigation and Other Contingencies

We are involved in a number of legal proceedings. In certain cases, plaintiffs seek to recover large or unspecified damages, and some matters may be unresolved for several years. We cannot currently determine the outcome of the proceedings described below or estimate the reasonable amount or range of potential losses, if any, and therefore have 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.

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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, would dismiss the actions. The settlement was based on the inclusion of additional disclosures in the Form S-4 filed with the SEC on September 13, 2010. On April 15, 2011, the court gave final approval to the settlement and awarded $555,000 of attorneys fees and expenses to plaintiffs counsel.

Scrubber Contract Litigation

In January 2011, Stone & Webster, the EPC contractor for the scrubber projects at the Chalk Point, Dickerson and Morgantown facilities, filed three suits against us in the United States District Court for the District of Maryland. Stone & Webster claims that it has not been paid in accordance with the terms of the EPC agreements for the scrubber projects and sought liens against the properties in the amounts of $43.2 million at Chalk Point, $46.8 million at Dickerson and $53.1 million at Morgantown. In March 2011, the court granted liens against the properties. The liens are interlocutory only and will not become final unless and until Stone & Webster is successful in prosecuting its contractual claims. As a result of certain lien restrictions in its lease documentation, GenOn Mid-Atlantic has reserved $143 million of cash (which is included in funds on deposit on the condensed consolidated balance sheet) in respect of such liens. We dispute Stone & Webster s allegations and in February 2011 filed a related action against Stone &Webster in the United States District Court for the Southern District of New York. 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.

Pending Natural Gas Litigation

We are party to five lawsuits, several of which are class action lawsuits, in state and federal courts in Kansas, Missouri, Nevada and Wisconsin. These lawsuits were filed in the aftermath of the California energy crisis and the resulting FERC investigations and 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. We have agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

Environmental Matters

Conemaugh Actions. In April 2007, PennEnvironment and the Sierra Club filed a citizens suit against us in the United States District Court, Western District of Pennsylvania to enforce provisions of the water discharge permit for the Conemaugh plant, of which we are the operator and have a 16.45% interest. PennEnvironment and the Sierra Club seek civil penalties, remediation and an injunction against further violations. We think 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. In March 2011, the court granted partial summary judgment on liability against us. A trial is scheduled for June 2011 to address the appropriate remedy and penalty. If PennEnvironment and the Sierra Club are ultimately successful, we could incur additional capital expenditures associated with the implementation of discharge reductions and penalties, which could be material to our financial position and cash flows.

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. Although we think claims such as this lack legal merit, it is possible that this trend of climate change litigation may continue.

Potomac River NOVs. In 2010, the Virginia DEQ issued several NOVs related to the Potomac River facility. Virginia DEQ asserted that we 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. We think 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 we combusted used oils in the facility s boilers without authority under the permit and received one shipment of coal that exceeded the maximum ash content allowed under the permit. In a fourth NOV, issued in February 2011, the Virginia DEQ asserted that in January 2011 we used a sorbent for the removal of SO_2 that was not permitted. We settled these alleged violations for $276,000 with the Virginia DEQ in early May 2011.

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. We estimate that the CO_2 levy will impose $10 million to $15 million per year in levies owed to Montgomery County. In June 2010, we 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 our complaint, we contend that the CO_2 levy violates our 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. We have 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. We are corresponding or have 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, we received an NOV from the EPA alleging that past work at our 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 us in the United States District Court for the Eastern District of 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 us 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.

We think 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 we 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 our ownership or lease of those facilities. We think that we are indemnified by or have the right to seek indemnification from the prior owners for certain losses and expenses that may be incurred from activities occurring prior to our ownership.

In addition, the New Jersey Department of Environmental Protection filed two administrative petitions with the EPA in 2010 alleging that our Portland generating facility s emissions were significantly contributing to nonattainment and/or interfering with the maintenance of certain NAAQS. In April 2011, the EPA addressed one of the two petitions and proposed to find that the SO_2 emissions from two of the units at the Portland facility significantly contribute to nonattainment and interfere with the maintenance of the one-hour SO_2 NAAQS in New Jersey. The EPA is seeking comment on proposals that would require these two units to reduce their SO_2 emission rates in two phases over a period of three years to address these concerns. If the proposed rule is finalized, the two units would need to reduce their SO_2 emission rates, which would require either capital expenditures and higher operating costs or the retirement of these two units, either of which could be material to our results of operations, financial position and cash flows.

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Maryland Fly Ash Facilities. We have three fly ash facilities in Maryland: Faulkner, Westland and Brandywine. Until recently, we disposed of fly ash from our Morgantown station at Faulkner. We currently dispose of fly ash from our Morgantown and Chalk Point facilities at Brandywine. We currently dispose of fly ash from our Dickerson station at Westland.

In May 2008, the MDE filed a complaint against us in the Circuit Court for Charles County, Maryland alleging violations of Maryland s water pollution laws at Faulkner. The MDE contended that the operation of Faulkner had resulted in the discharge of pollutants that exceeded Maryland s water quality criteria and without the appropriate NPDES permit. The MDE also alleged that we failed to perform certain sampling and reporting required under an applicable NPDES permit. The MDE complaint requested that the court (a) prohibit continuation of the alleged unpermitted discharges, (b) require us to cease from further disposal of any coal combustion byproducts at Faulkner and close and cap the existing disposal cells and (c) assess civil penalties. In July 2008, we filed a motion to dismiss the complaint, arguing that the discharges are permitted by a December 2000 Consent Order. In January 2011, MDE dismissed without prejudice its complaint and informed us that it intended to file a similar lawsuit in federal court. In May 2011, the MDE filed a complaint against us in the United States District Court for the District of Maryland alleging violations of the Clean Water Act and Maryland s Water Pollution Control Law at Faulkner. The MDE contends that (a) certain of our water discharges are not authorized by our existing permit and (b) operation of the Faulkner landfill has resulted in discharges of pollutants that violate water quality criteria. The complaint asks the court to, among other things, (a) enjoin further disposal of coal ash; (b) enjoin discharges that are not authorized by our existing permit; (c) require numerous technical studies; (d) impose civil penalties and (e) award them attorneys fees. We dispute the allegations.

In January 2011, the MDE informed us that it intends to file a complaint related to alleged violations of Maryland s water pollution laws at Westland.

In April 2010, the MDE filed a complaint against us 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 at Brandywine. The MDE contends that the operation of Brandywine 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 Brandywine, (b) require us to close and cap the existing open disposal cells within one year, (c) impose civil penalties and (d) award them attorney s fees. We dispute the allegations. In September 2010, four environmental advocacy groups became intervening parties in the proceeding. In March 2011, the MDE tentatively determined to deny our application for the renewal of the water discharge permit for Brandywine, which could result in a significant increase in operating expenses for our Chalk Point and Morgantown generating facilities.

The MDE has indicated that it is planning also to deny our applications for the renewal of the water discharge permits for Faulkner and Westland. Denial of the renewal of the water discharge permit for the latter facility could result in a significant increase in operating expenses for our Dickerson generating facility.

We have initiated discussions with the MDE to seek to resolve the dispute related to Brandywine along with the disputes related to Faulkner and Westland described above. We are examining a range of possible alternatives to address the MDE s concerns. If an alternative acceptable to the MDE is developed, we expect that the MDE would issue renewed, more-stringent (but yet to be developed) permits that would require us to take actions at these three facilities to achieve the more stringent standards. We cannot estimate the costs of the possible actions as they are still being developed but they likely would result in material expenditures (some of which could be capitalized), including possible penalties. There are no assurances that we will be able to resolve these three disputes with the MDE.

Ash Disposal Facility Closures. We are responsible for environmental costs related to the future closures of several ash disposal facilities. We have accrued the estimated discounted costs ($37 million and $36 million at March 31, 2011 and December 31, 2010, respectively) associated with these environmental liabilities as part of the asset retirement obligations.

Remediation Obligations. We are responsible for environmental costs related to site contamination investigations and remediation requirements at four generating facilities in New Jersey. We have accrued the estimated long-term liability for the remediation costs of $7 million at March 31, 2011 and 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 us. 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 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 GenOn Energy Holdings 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 United States District Court for 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. We recognized the $52 million as a reduction of operations and maintenance expense during 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 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 we have received or expect 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. None of the RPM Buyers asked the D.C. Circuit to reconsider its decision. The deadline for any party to file for a writ of certiorari with the Supreme Court is May 9, 2011.

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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 our retail business in 2009, we were a retail energy provider. CenterPoint sought recovery of EMCs that it credited to all retail energy providers, including us, and in December 2004 the PUCT ordered that relief. CenterPoint represents that EMCs credited to us totaled $385 million. On appeal, the Texas Third Circuit Court of Appeals ruled that CenterPoint s recovery should exclude EMCs credited to us for our price-to-beat customers, which CenterPoint represents totaled $385 million. Following that ruling, CenterPoint indicated that in the event it was unable to recover the EMC credits applied to us through its rates, it might assert a claim against us for such credits. CenterPoint appealed this ruling to the Texas Supreme Court. On March 18, 2011, the Texas Supreme Court overturned the appeals court and ruled that CenterPoint is entitled to recover as stranded costs EMCs credited to us. In light of the Texas Supreme Court s decision, we think CenterPoint will not assert such a claim.

Texas Franchise Audit

In 2008 and 2009, the state of Texas, as a result of its audit, issued franchise tax assessments against us indicating an underpayment of franchise tax of approximately $69 million (including interest and penalties through March 31, 2011 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. We disagree with most of the State s assessment and its determination of the related tax liability. Given the disagreement with the State s position, we have accrued a portion of the liability but have protested the entire assessment and are currently in the administrative appeals process. If we do not fully resolve or come to satisfactory settlement of the protested issues, then we could pay up to the entire amount of the assessed tax, penalties and interest. We intend to defend fully our position in the administrative appeals process and if such defense requires litigation, would be required to pay the full assessment and sue for refund.

ITEM 2. 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 interim financial statements, the changes in those financial statements from period to period and the primary factors contributing to those changes. The following discussion should be read in conjunction with our interim financial statements and our 2010 Annual Report on Form 10-K.

Overview

With approximately 24,200 MW of net electric generating capacity, we operate across various fuel (natural gas, coal and oil) and technology types, operating characteristics and regional power markets. At March 31, 2011, our generating capacity was 50% in PJM, 22% in CAISO, 11% in NYISO and ISO-NE, 10% in the Southeast and 7% in MISO.

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.

Merger of Mirant and RRI Energy

On December 3, 2010, Mirant and RRI Energy completed their Merger. See note 2 to our interim financial statements for further discussion of the Merger.

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 (and any other financial or operational information presented herein with respect to such pre-merger dates, unless otherwise specified) 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.

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 have some risks resulting from price differentials for different delivery points. In addition, we have risks 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 April 12, 2011, our aggregate hedge levels based on expected generation were as follows:

	2011(1)	2012	2013	2014	2015
Power	79%	48%	18%	16%	3%
Fuel	91%	40%	26%	7%	7%

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

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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 will provide. The effect of the Dodd-Frank Act on our business depends in large measure on pending rulemaking proceedings of the CFTC, the SEC and the federal banking regulators. Under the Dodd-Frank Act, entities defined as swap dealers and major swap participants (SD/MSPs) will face costly requirements for clearing and posting margin, as well as additional requirements for reporting and business conduct. The CFTC and SEC issued a proposed rulemaking to set final definitions for the terms swap dealer and major swap participant among others. Although we do not expect our hedging activity to result in our designation as an SD/MSP, as proposed, the swap dealer definition in particular is ambiguous, subjective and could be broad enough to encompass some energy companies. In addition, the CFTC and federal banking regulators, who will regulate bank SD/MSPs, separately issued proposed rules to establish capital and margin requirements for SD/MSPs and swap counterparties. While end-user counterparties who are using a swap to hedge or mitigate commercial risk would be generally exempt from mandatory margin requirements under the CFTC s proposal applicable to non-bank SD/MSPs, they would have to post cash margin to bank SD/MSPs if they exceed exposure thresholds under the federal banking regulators proposal. The federal banking regulators rulemaking states that the credit support limit shall be determined by the bank SD/MSPs in accordance with their normal credit processes to set credit limits and to collect initial and variation margin. As proposed, the federal banking regulators rulemaking does not specify a procedure for determining such thresholds and a major question remains of the extent to which end-users and bank SD/MSPs will be free under the proposal to set their own thresholds to avoid the collection of margin from end-users. If applied to our hedging activity, such regulations could materially affect our ability to hedge economically our generation by significantly increasing the collateral costs associated with such activities.

Capital Expenditures and Capital Resources

During the three months ended March 31, 2011, we invested $97 million for capital expenditures, excluding capitalized interest paid, primarily related to the construction of the Marsh Landing generating facility and maintenance capital expenditures. At March 31, 2011, we have invested $1.52 billion of the $1.674 billion that was budgeted for capital expenditures related to compliance with the Maryland Healthy Air Act. Provisions in the construction contracts for the scrubbers at three of our largest Maryland coal-fired units 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 11 to our interim financial statements for further discussion of the scrubber contract litigation.

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 the remainder of 2011 and 2012:

	April 1, 2011 through December 31, 2011	2012
	(in millions)	
Maryland Healthy Air Act	$ 154	$
Other environmental	39	47
Maintenance	94	89
Marsh Landing generating facility	150	305
Other construction	45	7

Other		19		12
Total	$	501	$	460

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 GenOn Marsh Landing entered in October 2010. 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

Several proposed environmental regulations are pending. The dates of final regulations and implementation deadlines are difficult to predict. The following summarizes material first quarter 2011 environmental regulatory developments. See also our discussion under the caption Environmental Matters in note 11 to our interim financial statements, including the discussion of petitions filed by the New Jersey Department of Environmental Protection related to our Portland facility and the discussion of the process for obtaining renewals from the MDE of water discharge permits for our Brandywine, Faulkner and Westland ash facilities. Our 2010 Annual Report on Form 10-K contains discussion of other pending environmental matters, including the proposed Transport Rule and the water permit at our Shawville facility.

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. In May 2011, the EPA proposed emission standards for HAPs from coal- and oil-fired units. The EPA proposes to establish limits for mercury, non-mercury metals, certain organics and acid gases. If finalized, these MACT standards will require us to install and operate additional emissions control equipment at some of our facilities, the cost of which may be material and may result in the shutdown or retirement of some of our coal-fired facilities for which operating economics do not justify the required capital expenditures.

AB 32. 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. In March 2011, a California superior court judge enjoined the implementation of the cap-and-trade program and related Scoping Plan measures until CARB remedies various procedural flaws related to CARB s environmental review of the Scoping Plan under the California Environmental Quality Act, possibly delaying the scheduled January 2012 implementation date. Our California generating facilities will be required to comply with the cap-and-trade regulations and related rules when they go into effect. 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.

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 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. In April 2011, the EPA proposed a 316(b) rule that would apply to virtually all existing facilities, including power plants that use cooling water intake structures to withdraw water from waters of the United States. That proposal would impose national standards for reducing mortality for larger, impingeable-sized organisms. It requires permit writers to establish controls for smaller, entrainable-sized organisms on a site-specific basis, taking into account a variety of factors, including costs and benefits. The EPA will accept public comment on its proposal until July 19, 2011, and the final rule may differ from the proposal as a result of that process. Until the EPA issues the final rule, which it has committed to do by July 2012, there is significant uncertainty regarding what technologies or other measures will be needed to satisfy section 316(b) regulations.

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 asserted that there was insufficient public notice of the final permit. They also asserted 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 disagreed with these allegations and thought that all of the issues raised had been adequately and appropriately addressed. In May 2011, the appeal was dismissed because plaintiffs voluntarily dismissed their challenge.

Potrero Shutdown

On February 28, 2011, the Potrero facility was shut down. See note 19 to our consolidated financial statements in our 2010 Annual Report on Form 10-K 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 baseload coal units is negatively affected by these price levels. For that portion of the volumes of generation that we have hedged, we are generally unaffected by 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 to manage the risks associated with volatility in prices and to achieve more predictable realized gross margin.

Results of Operations

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 operations and adjusted EBITDA as consolidated performance measures, which exclude unrealized gross margin. These are also provided on a pro forma basis for the three months ended March 31, 2010. As mentioned above, management generally evaluates our operating results excluding the effect of unrealized gains and losses. Adjusted income from operations and adjusted EBITDA also exclude items related to the Merger, net lower of cost or market adjustments to our commodity inventories, impairment losses (on a pro forma basis) 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 assets among otherwise comparable companies. We encourage our investors to review our financial statements and other publicly filed reports in their entirety and not to rely on a single financial measure.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

Consolidated Financial Performance

We reported net loss of $113 million and net income of $407 million during the three months ended March 31, 2011 and 2010, respectively. The change in net income/loss is detailed as follows:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Increase/ (Decrease)
		(in millions)	
Realized gross margin	$ 489	$ 321	$ 168
Unrealized gross margin	(79)	352	(431)
Total gross margin (excluding depreciation and amortization)	410	673	(263)
Operating expenses:			
Operations and maintenance	304	166	138
Depreciation and amortization	86	51	35
Gain on sales of assets, net	(1)	(2)	1
Total operating expenses	389	215	174
Operating income	21	458	(437)
Other income (expense), net:			
Interest expense, net	(109)	(50)	(59)
Other, net	(22)	(1)	(21)
Total other expense, net	(131)	(51)	(80)
Income (loss) before income taxes	(110)	407	(517)
Provision for income taxes	3		3
Net income (loss)	$ (113)	$ 407	$ (520)

Realized Gross Margin. Our realized gross margin increase of $168 million was principally a result of the following:

- an increase of $93 million in contracted and capacity primarily as a result of $114 million from the addition of RRI Energy generating facilities as a result of the Merger, partially offset by a decrease of $21 million primarily resulting from lower capacity prices in our Eastern PJM segment;
- an increase of $64 million in energy primarily as a result of $78 million from the addition of RRI Energy generating facilities as a result of the Merger, offset in part by a decrease in generation volumes in Eastern PJM primarily as a result of contracting dark spreads; and

an increase of $11 million in realized value of hedges primarily as a result of $13 million from the addition of RRI Energy generating facilities as a result of the Merger.

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

- unrealized losses of $79 million during the three months ended March 31, 2011, which included $69 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $10 million net decrease in the value of hedge and proprietary trading contracts for future periods. The decrease in value was primarily related to increases in oil prices, offset by decreases in forward power and natural gas prices; and
- unrealized gains of $352 million during the three months ended March 31, 2010, which included a $433 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 $81 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 $174 million was principally a result of the following:

- an increase of $138 million in operations and maintenance expense primarily as a result of the addition of RRI Energy generating facilities and corporate costs as a result of the Merger, and an increase of $21 million in merger-related costs primarily for severance; and
- an increase of $35 million in depreciation and amortization expense primarily as a result of the addition of the long-lived assets acquired in the Merger, partially offset by a decrease as a result of a decrease in the carrying value of the Dickerson and Potomac River generating facilities as a result of impairment losses taken in the fourth quarter 2010, and shutdown of the Potrero generating facility.

Interest Expense, Net. Interest expense, net increase of $59 million was principally a result of the following:

- $71 million increase related to interest incurred on our senior notes and credit facilities and interest expense on debt assumed in the Merger; partially offset by
- $20 million decrease related to lower interest expense as a result of repayment of the GenOn North America senior secured credit facilities and senior notes in December 2010 and January 2011, respectively.

Other, Net. Other, net change of $21 million was principally a result of the following:

- $24 million of other expense relating to the loss on extinguishment of debt primarily related to a $16 million premium and a $7 million write-off of unamortized debt issuance costs related to the GenOn North America senior notes that were repaid in 2011.

Adjusted Income from Operations and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted income from operations and adjusted EBITDA to net income/loss on historical and pro forma bases. See the discussion above and note (1) below regarding the significant items excluded or adjusted in arriving at the non-GAAP measures in the table below. In order to provide a more meaningful comparison of our results, the following compares actual results for the three months ended March 31, 2011 to pro forma information for the three months ended March 31, 2010 and provides discussion of the changes. The unaudited pro forma information is based on the historical consolidated financial statements of both RRI Energy and Mirant and has been prepared to illustrate the effects of the Merger, assuming the Merger had been consummated on January 1, 2010. 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:

merger-related costs because these costs reflect non-recurring charges directly related to the Merger; and

cost savings from operating efficiencies or synergies that we expect to result from the Merger.

The pro forma financial information is not necessarily indicative of the operating results that would have occurred if the Merger had been completed at the date indicated, nor is it indicative of our future operating results.

	Three Months Ended March 31,		
	2011	Pro Forma 2010	2010
		(in millions)	
Net Income (Loss)	$ (113)	$ 220	$ 407
Unrealized (gains) losses	79	(479)	(352)
Impairment losses		248(1)	
Merger-related costs	23		2
Western states litigation and similar settlements		17(1)	
Lower of cost or market inventory adjustments, net	(8)	(14)	3
Loss on early extinguishment of debt	24		
Other		2	1
Adjusted income (loss) from operations	5	(6)	61
Interest expense, net	109	101	50
Provision for income taxes	3		
Depreciation and amortization	86	94	51
Adjusted EBITDA	$ 203	$ 189	$ 162

(1) During the three months ended March 31, 2010, RRI Energy recognized (a) impairment losses of $248 million for its Elrama and Niles generating facilities and (b) $17 million to settle the western states and other litigation.

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Adjusted EBITDA was $203 million for the three months ended March 31, 2011 compared to $189 million on a pro forma basis for the same period of 2010. The improvement was primarily related to lower adjusted operating and other expenses and increased realized value of hedges. These improvements were partially offset by a reduction in energy gross margin as a result of reduced generation volumes in Eastern PJM and lower contracted and capacity revenues from Eastern PJM and California.

The adjusted income from continuing operations was $5 million for the three months ended March 31, 2011 compared to an adjusted loss from continuing operations of $6 million on a pro forma basis for the same period of 2010. The improvement was primarily related to the same items that affected adjusted EBITDA.

Our net loss was $113 million for the three months ended March 31, 2011 compared to net income of $220 million on a pro forma basis for the same period of 2010. The decline was primarily a result of lower unrealized gross margin and an increase in merger-related costs. These were partially offset by impairment losses in 2010 related to the Elrama and Niles generating facilities that were not repeated in 2011 and the same items that affected adjusted EBITDA.

Segments

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

In the tables below, for 2011, 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 seven generating facilities located in California and includes business development and construction activities for GenOn Marsh Landing. These seven generating facilities exclude the Potrero generating facility which was shut down on February 28, 2011. 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 Florida, Massachusetts, Mississippi, New York and Texas. Other Operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

Gross Margin Overview

The following tables detail realized and unrealized gross margin by operating segments:

	Three Months Ended March 31, 2011						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations[1]	Total
				(in millions)			
Energy	$ 61	$ 73	$	$ 38	$ 4	$ (2)	$ 174
Contracted and capacity	93	85	33		24		235
Realized value of hedges	63	12	1		4		80
Total realized gross margin	217	170	34	38	32	(2)	489
Unrealized gross margin	(39)	(9)		(22)	(9)		(79)
Total gross margin[2]	$ 178	$ 161	$ 34	$ 16	$ 23	$ (2)	$ 410

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	Three Months Ended March 31, 2010						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing	Other Operations	Eliminations	Total
				(in millions)			
Energy	$ 92	$	$	$ 21	$ (3)	$	$ 110
Contracted and capacity	89		30		23		142
Realized value of hedges	57				12		69
Total realized gross margin	238		30	21	32		321
Unrealized gross margin	346			10	(4)		352
Total gross margin(2)	$ 584	$	$ 30	$ 31	$ 28	$	$ 673

(1) Primarily relates to intercompany sales of emissions allowances.

(2) 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, 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 (through February 28, 2011), 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.

Operating Statistics

Our total margin capture factor was 89% during the three months ended March 31, 2011. The following table summarizes power generation volumes by segment:

	Three Months Ended March 31, 2011	2010 (in gigawatt hours)	Increase/ (Decrease)	Increase/ (Decrease)
Eastern PJM:				
Baseload	3,511	3,972	(461)	(12)%
Intermediate	18	55	(37)	(67)%
Peaking	18	6	12	200%
Total Eastern PJM	3,547	4,033	(486)	(12)%
Western PJM/MISO:				
Baseload	4,292		4,292	N/A
Intermediate	714		714	N/A
Peaking(1)	(1)		(1)	N/A
Total Western PJM/MISO	5,005		5,005	N/A
California:				
Intermediate	33	123	(90)	(73)%
Total California	33	123	(90)	(73)%
Other Operations:				
Baseload	378	365	13	4%
Intermediate	18	9	9	100%
Peaking	11		11	N/A
Total Other Operations	407	374	33	9%
Total	8,992	4,530	4,462	98%

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

The total increase in power generation volumes during the three months ended March 31, 2011, as compared to the same period in 2010, is primarily the result of the following:

Eastern PJM. A decrease in our baseload and intermediate generation volumes primarily as a result of contracting dark spreads, partially offset by an increase in our peaking generation and the addition of the RRI Energy generating facilities as a result of the Merger.

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

California. The decrease in our intermediate generation volumes is primarily the result of the shutdown of the Potrero generating facility.

Other Operations. An increase in our Other Operations baseload and intermediate generation as a result of lower average temperatures in the Northeast and increased peaking generation as a result of the addition of the southeast assets as a result of the Merger.

Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,336 MW at March 31, 2011 and four generating facilities with total net generating capacity of 5,204 MW at March 31, 2010.

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010 (in millions)	Increase/ (Decrease)
Gross Margin:			
Energy	$ 61	$ 92	$ (31)
Contracted and capacity	93	89	4
Realized value of hedges	63	57	6
Total realized gross margin	217	238	(21)
Unrealized gross margin	(39)	346	(385)
Total gross margin (excluding depreciation and amortization)	178	584	(406)
Operating Expenses:			
Operations and maintenance	106	113	(7)
Depreciation and amortization	31	33	(2)
Gain on sales of assets, net		(2)	2
Total operating expenses, net	137	144	(7)
Operating income	$ 41	$ 440	$ (399)

Gross Margin

The decrease of $21 million in realized gross margin was principally a result of the following:

- a decrease of $31 million in energy, primarily as a result of a decrease in generation volumes as a result of contracting dark spreads;
- an increase of $6 million in realized value of hedges, primarily as a result of an $18 million increase in our coal hedges resulting from prices, offset in part by a $12 million decrease in power hedges resulting from prices; and
- an increase of $4 million in contracted and capacity primarily related to the addition of the RRI Energy generating facilities as a result of the Merger, offset in part by lower capacity prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $39 million during the three months ended March 31, 2011, which included $54 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period offset by a $15 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and increases in forward coal prices; and
- unrealized gains of $346 million during the three months ended March 31, 2010, which included a $396 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 $50 million associated with the

reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

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Operating Expenses

The decrease of $7 million was principally a result of a decrease of $7 million in operations and maintenance expense primarily as a result of a decrease in outage expense incurred during the three months ended March 31, 2011 compared to the same period in 2010.

Western PJM/MISO

Our Western PJM/MISO segment was established as a result of the Merger and includes 23 generating facilities (all RRI Energy generating facilities) with total net generating capacity of 7,483 MW at March 31, 2011.

The following table summarizes the results of operations of our Western PJM/MISO segment:

	Three Months Ended March 31,		Increase/
	2011	2010	(Decrease)
		(in millions)	
Gross Margin:			
Energy	$ 73	$	$ 73
Contracted and capacity	85		85
Realized value of hedges	12		12
Total realized gross margin	170		170
Unrealized gross margin	(9)		(9)
Total gross margin (excluding depreciation and amortization)	161		161
Operating Expenses:			
Operations and maintenance	110		110
Depreciation and amortization	25		25
Total operating expenses, net	135		135
Operating income	$ 26	$	$ 26

California

Our California segment consists of seven generating facilities with total net generating capacity of 5,363 MW (excluding the Potrero facility of 362 MW, which was shut down on February 28, 2011) at March 31, 2011 and three generating facilities with total net generating capacity of 2,347 MW at March 31, 2010. Our California segment also includes business development and construction activities for new generation in California, including GenOn Marsh Landing.

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Increase/ (Decrease)
	(in millions)		
Gross Margin:			
Energy	$	$	$
Contracted and capacity	33	30	3
Realized value of hedges	1		1
Total realized gross margin	34	30	4
Unrealized gross margin			
Total gross margin (excluding depreciation and amortization)	34	30	4
Operating Expenses:			
Operations and maintenance	39	20	19
Depreciation and amortization	14	8	6
Gain on sales of assets, net			
Total operating expenses, net	53	28	25
Operating income (loss)	$ (19)	$ 2	$ (21)

Gross Margin

Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for the majority of the capacity from these units, and our Potrero units were subject to RMR arrangements through February 28, 2011. 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 increase of $25 million in operating expenses was principally a result of the following:

- an increase of $19 million in operations and maintenance expense related to the addition of the RRI Energy facilities as a result of the Merger partially offset by decreased operations and maintenance expense as a result of the shutdown of the Potrero generating facility; and
- an increase of $6 million in depreciation and amortization expense related to the addition of the RRI Energy facilities as a result of the Merger partially offset by a decrease as a result of the shutdown of the Potrero generating facility.

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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:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Increase/ (Decrease)
	(in millions)		
Gross Margin:			
Energy	$ 38	$ 21	$ 17
Total realized gross margin	38	21	17
Unrealized gross margin	(22)	10	(32)
Total gross margin (excluding depreciation and amortization)	16	31	(15)
Operating Expenses:			
Operations and maintenance	4	2	2
Total operating expenses, net	4	2	2
Operating income	$ 12	$ 29	$ (17)

Gross Margin

The increase of $17 million in realized gross margin was principally a result of our fuel oil management activities, primarily from the sales of fuel oil.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $22 million during the three months ended March 31, 2011, which included a $16 million net decrease in the value of contracts for future periods and $6 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and
- unrealized gains of $10 million during the three months ended March 31, 2010, which included a $31 million net increase in the value of trading contracts for future periods, partially offset by $21 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Other Operations

Our Other Operations segment consists of nine generating facilities with total net generating capacity of 5,055 MW at March 31, 2011 and four generating facilities with total net generating capacity of 2,535 MW at March 31, 2010. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

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

	Three Months Ended March 31, 2011	2010	Increase/ (Decrease)
	(in millions)		
Gross Margin:			
Energy	$ 4	$ (3)	$ 7
Contracted and capacity	24	23	1
Realized value of hedges	4	12	(8)
Total realized gross margin	32	32	
Unrealized gross margin	(9)	(4)	(5)
Total gross margin (excluding depreciation and amortization)	23	28	(5)
Operating Expenses:			
Operations and maintenance	45	31	14
Depreciation and amortization	16	10	6
Gain on sales of assets, net	(1)		(1)
Total operating expenses, net	60	41	19
Operating loss	$ (37)	$ (13)	$ (24)

Gross Margin

The net change of $0 in realized gross margin was principally a result of the following:

- a decrease of $8 million in realized value of hedges primarily as a result of a decline in the value realized from our power, oil and gas hedges, partially offset by
- an increase of $7 million in energy primarily as a result of increases in prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $9 million during the three months ended March 31, 2011, 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 $3 million net decrease in the value of hedge contracts for future periods; and
- unrealized losses of $4 million during the three months ended March 31, 2010, which included $10 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, partially offset by a $6 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and fuel prices.

Operating Expenses

The increase of $19 million in operating expenses was principally the result of the following:

- an increase of $14 million in operations and maintenance expense primarily related to an increase of $21 million in merger-related costs, partially offset by a decrease as a result of a change in the methodology of allocating costs to reportable segments; and
- an increase of $6 million in depreciation and amortization expense primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger.

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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 5 to our interim financial statements for additional discussion of our debt.

Sources of Funds and Capital Structure

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 March 31, 2011 (in millions):

Cash and Cash Equivalents:		
GenOn (excluding GenOn Mid-Atlantic and REMA)	$	2,192
GenOn Mid-Atlantic		131
REMA		67
Total cash and cash equivalents		2,390
Less: cash reserved for other purposes		(12)
Total available cash and cash equivalents		2,378
Availability under GenOn credit facilities(1)		542
Total available cash, cash equivalents and availability under GenOn credit facilities(1)	$	2,920

(1) Availability under the GenOn credit facilities does not include availability under the 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 March 31, 2011, 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) On May 2, 2011, we repaid the $535 million of senior notes that came due.

(3) At March 31, 2011, GenOn Marsh Landing had not drawn on its credit facility.

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 March 31, 2011, GenOn Mid-Atlantic and REMA satisfied the respective restricted payments tests.

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.

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.

Repayment of Debt. On January 3, 2011, we used the proceeds from the merger-related debt issuances to redeem $285 million (principal and 2.25% premium) of GenOn senior secured notes due 2014 and $866 million (principal and 1.844% premium) of GenOn North America senior unsecured notes due 2013. On May 2, 2011, we repaid GenOn Americas Generation s $535 million of senior notes that came due. See note 5 to our interim financial statements.

Capital Expenditures. Our capital expenditures, excluding capitalized interest paid, during the three months ended March 31, 2011, were $97 million. We estimate our capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for the period April 1, 2011 through December 31, 2012 will be $961 million. See Capital Expenditures and Capital Resources for further discussion of our capital expenditures.

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 March 31, 2011, we had $263 million of posted cash collateral and $246 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 $152 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.

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

	March 31, 2011	December 31, 2010
	(in millions)	
Cash collateral posted energy trading and marketing	$ 218	$ 220
Cash collateral posted other operating activities	45	45
Letters of credit Marsh Landing project	152	106
Letters of credit rent reserves	142	133
Letters of credit energy trading and marketing	63	96
Letters of credit other operating activities	41	38
Surety bonds[1]	47	50
Total	$ 708	$ 688

(1) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at March 31, 2011 and December 31, 2010.

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

Other than the repayment of the GenOn senior secured notes and the GenOn North America senior notes on January 3, 2011 and the GenOn Americas Generation senior unsecured notes on May 2, 2011, there have been no significant changes to our debt obligations, off-balance sheet arrangements and contractual obligations from those presented in our 2010 Annual Report on Form 10-K.

Historical Cash Flows

Continuing Operations

Operating Activities. 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 $84 million for the three months ended March 31, 2011, compared to the same period in 2010, primarily as a result of the following:

- *Operating expenses.* An increase in cash used related to higher operations and maintenance expense of $139 million primarily as a result of the addition of RRI Energy generating facilities as a result of the Merger and an increase in merger-related costs. See Results of Operations in Item 2 for additional discussion of our performance in 2011 compared to the same period in 2010;
- *Accounts payable, collateral*. A decrease in cash provided of $78 million primarily as a result of $1 million returned to our counterparties in 2011 compared to $77 million posted by our counterparties in 2010;
- *Net accounts receivables and accounts payables*. An increase in cash used of $34 million primarily as a result of decreases in the settlement prices of our power hedges;
- *Funds on deposit*. A decrease in cash provided of $28 million primarily as a result of $42 million of additional collateral posted with our counterparties in 2011 compared to $14 million of additional collateral posted in 2010; and
- *Other operating assets and liabilities*. A decrease in cash provided of $21 million related to changes in other operating assets and liabilities.

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The increase in cash used in and decrease in cash provided by operating activities was partially offset by the following:

Realized gross margin. An increase in cash provided of $155 million in 2011 compared to the same period in 2010 (excluding the out of market contract amortization of $5 million in 2011 and lower of cost or market inventory adjustments of $8 million in 2010) primarily as a result of the addition of RRI Energy generating facilities as a result of the Merger. See Results of Operations in Item 2 for additional discussion of our performance in 2011 as compared to the same period in 2010; and

Inventory. A decrease in cash used of $61 million primarily related to the changes in fuel oil inventory.

Investing Activities. Net cash provided by investing activities increased by $1.006 billion for the three months ended March 31, 2011, compared to the same period in 2010. This difference was primarily a result of the following:

Withdrawals from restricted funds on deposit. An increase in cash provided of $1.163 billion primarily related to funds received from the GenOn debt financing on December 3, 2010, which were subsequently placed in restricted deposits at December 31, 2010. The withdrawal of cash was used to repay long-term debt. See note 5 to our interim financial statements;

Payments into restricted funds on deposit. A decrease in cash provided of $143 million primarily related to funds placed in restricted deposits as a result of our scrubber contract litigation and related liens. See note 11 to our interim financial statements; and

Capital expenditures. An increase in cash used of $11 million primarily related to the construction of our Marsh Landing generating facility, partially offset by a decrease in cash used as a result of payments related to our Maryland scrubber projects in 2010.

Financing Activities. Net cash used in financing activities increased by $1.084 billion for the three months ended March 31, 2011, compared to the same period in 2010. This difference was primarily a result of the repayment of long-term debt. See note 5 to our interim financial statements.

Critical Accounting Estimates

See Management s Discussion and Analysis of Financial Condition and Results of Operations, in Item 7 in our 2010 Annual Report on Form 10-K.

Recently Adopted Accounting Guidance

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

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our 2010 Annual Report on Form 10-K and notes 1 and 4 to our interim financial statements.

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 $637 million and $1.1 billion at March 31, 2011 and 2010, respectively. The following tables provide a summary of the factors affecting the change in fair value of the derivative contract asset and liability accounts for the three months ended March 31, 2011 and 2010:

	Commodity Contracts		Other Contracts	
	Asset Management	Trading	Interest Rate	Total
	(in millions)			
Fair value of portfolio of assets and liabilities at January 1, 2011	$ 706	$ (5)	$ 19	$ 720
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value[1]	(2)	(15)	3	(14)
Purchases[2]				
Issuances[2]				
Settlements[3]	(61)	(8)		(69)
Fair value of portfolio of assets and liabilities at March 31, 2011	$ 643	$ (28)	$ 22	$ 637
Fair value of portfolio of assets and liabilities at January 1, 2010	$ 701	$ 1	$	$ 702
Gains (losses) recognized in the period, net:				
New contracts and other changes in fair value[1]	333	11		344
Roll off of previous values[4]	(60)	(21)		(81)
Purchases[2]				
Issuances[2]				
Settlements[5]	70	19		89
Fair value of portfolio of assets and liabilities at March 31, 2010	$ 1,044	$ 10	$	$ 1,054

(1) Represents 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) Contracts entered into during each quarterly reporting period are reported with other changes in fair value.

(3) Effective January 1, 2011, represents the reversal of previously recognized unrealized gains and losses from settlement of contracts during each quarterly reporting period.

(4)

Represents the reversal of previously recognized unrealized gains and losses from the settlement of contracts during each quarterly reporting period.

(5) Represents the total cash settlements of contracts during each quarterly reporting period that existed at the beginning of each quarterly reporting period.

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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.

At March 31, 2011, the estimated net fair value of our derivative contract assets and liabilities are (asset (liability)):

Sources of Fair Value	Remainder of 2011	2012	2013	2014	2015	2016 and thereafter	Total fair value
				(in millions)			
Asset Management:							
Prices actively quoted (Level 1)	$ (8)	$ (8)	$	$	$	$	$ (16)
Prices provided by other external sources (Level 2)	183	162	184	181			710
Prices based on models and other valuation methods (Level 3)	(21)	(34)	4				(51)
Total asset management	$ 154	$ 120	$ 188	$ 181	$	$	$ 643
Trading Activities:							
Prices actively quoted (Level 1)	$ 1	$ (6)	$	$	$	$	$ (5)
Prices provided by other external sources (Level 2)	(27)	1					(26)
Prices based on models and other valuation methods (Level 3)	3						3
Total trading activities	$ (23)	$ (5)	$	$	$	$	$ (28)
Interest Rate:							
Prices actively quoted (Level 1)	$	$	$	$	$	$	$
Prices provided by other external sources (Level 2)					3	19	22
Prices based on models and other valuation methods (Level 3)							
Total interest rate	$	$	$	$	$ 3	$ 19	$ 22

The fair values shown in the table above are subject to significant changes as a result of fluctuating commodity forward market prices, forward market implied volatilities and credit risk. For further discussion of how we determine these fair values, see 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 our 2010 Annual Report on Form 10-K and note 4 to our interim financial statements.

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 $15 million and $21 million at March 31, 2011 and December 31, 2010, 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 March 31, 2011, 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 $1 million in our credit reserve at March 31, 2011.

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 to our interim financial statements for further discussion of our counterparty credit concentration risk.

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. We estimate that a one percentage point change in market interest rates would result in a change of $19 million to our derivative contract assets and a change of $6 million to our derivative contract liabilities at March 31, 2011.

Debt

Some of our debt is subject to variable interest rates, including our $697 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, we estimate 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 one and three counterparties at March 31, 2011 and December 31, 2010, respectively, 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 61% and 76% of our total coal commitments at March 31, 2011 and December 31, 2010, respectively.

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 to our interim financial statements for 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 March 31, 2011, and are projected to provide a $101 million benefit to our realized value of hedges through 2013 as the coal is utilized in the production of electricity.

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ITEM 4. 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 March 31, 2011. Based upon this assessment, our management concluded that, as of March 31, 2011, the design and operation of these disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

We continue to integrate certain business operations, information systems (including commercial accounting systems), processes and related internal control over financial reporting as a result of the Merger. During the quarter ended March 31, 2011, these changes included adopting a single enterprise wide resource planning system. We will continue to assess the effectiveness of our internal control over financial reporting as we execute merger integration activities.

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PART II

ITEM 1. LEGAL PROCEEDINGS

See note 11 to our interim financial statements for discussion of the material legal proceedings to which we are a party, including material developments during the first quarter of 2011.

ITEM 1A. RISK FACTORS

Part I, Item 1A, Risk Factors of our 2010 Annual Report on Form 10-K includes a discussion of our risk factors. There have been no material changes in our risk factors since those reported in our 2010 Annual Report on Form 10-K.

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ITEM 6. EXHIBITS

Exhibit No.	Exhibit Name
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)
3.3	Certificate of Amendment to the Third Restated Certificate of Incorporation of Registrant, dated May 5, 2011 (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Form 8-K filed May 9, 2011)
3.4	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	Registration Rights Agreement by and among RRI Energy, Inc., J.P. Morgan Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities, Inc., Goldman, Sachs & Co. and Morgan Stanley & Co. Incorporated, dated as of October 4, 2010 (Incorporated by reference to Exhibit 10.2 to the Registrant s Quarterly Report on Form 10-Q filed November 3, 2010)
4.5	The Company agrees to furnish to the Securities and Exchange Commission, upon request, a copy of any instrument defining the rights of holders of long-term debt of the Company and all of its consolidated subsidiaries for which financial statements are required to be filed with the Securities and Exchange Commission.
10.1*	2011 Restricted Stock Unit Award Agreement for Edward R. Muller under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, dated February 23, 2011
10.2*	2011 Performance Unit Award Agreement for Edward R. Muller under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, dated February 23, 2011
10.3*	2011 Nonqualified Stock Option Award Agreement for Edward R. Muller under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan, dated February 23, 2011

10.4*	Form of 2011 Restricted Stock Unit Award Agreement for Officers under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan
10.5*	Form of 2011 Performance Unit Award Agreement for Officers under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan
10.6*	Form of 2011 Nonqualified Stock Option Award Agreement for Officers under the GenOn Energy, Inc. 2010 Omnibus Incentive Plan

Exhibit No.	Exhibit Name
10.7	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financial 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 August 20, 2009 (Incorporated herein by reference to Exhibit 99.2 to the Registrant s Current Report on Form 8-K filed August 24, 2009)
31.1*	Certification of the Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a))
31.2*	Certification of the Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(a))
32.1*	Certification of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted 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 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Rule 13a-14(b))
101*	Interactive Data File

* Asterisk indicates exhibits filed herewith.

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SIGNATURES

Pursuant to the requirements 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.

Date: May 9, 2011

By: /s/ THOMAS C. LIVENGOOD
Thomas C. Livengood
Senior Vice President and Controller
(Duly Authorized Officer and
Principal Accounting Officer)