GenOn Energy, Inc.
Form 10-Q
November 09, 2011
Table of Contents

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 September 30, 2011

OR

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

For the transition period from to

Commission File Number: 1-16455

GenOn Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)

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

(832) 357-3000

(Registrant s Telephone Number, Including Area Code)

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 ¨ 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 ¨ 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 ¨
Non-accelerated Filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

As of November 1, 2011, there were 771,692,734 shares of the registrant s Common Stock, $0.001 par value per share, outstanding.

Table of Contents

TABLE OF CONTENTS

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.
CO_2	Carbon dioxide.
CSAPR	Cross-State Air Pollution Rule.

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).

Table of Contents

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 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).
HAPs	Hazardous Air Pollutants.
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.
NJDEP	New Jersey Department of Environmental Protection.
NOL	Net operating loss.
NOV	Notice of violation.
NO_x	Nitrogen oxides.
NPDES	National pollutant discharge elimination system.
NYISO	New York Independent System Operator.

Table of Contents

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.
PEPCO	Potomac Electric Power Company.
PG&E	Pacific Gas & Electric Company.
PJM	PJM Interconnection, LLC.
Plan	The plan of reorganization that was approved in conjunction with Mirant Corporation s emergence from bankruptcy protection on January 3, 2006.
PPA	Power purchase agreement.
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.
RRI Energy	RRI Energy, Inc., which changed its name to GenOn Energy, Inc. in connection with the Merger.
RTO	Regional Transmission Organization.
SCR	Selective catalytic reduction emissions controls.

scrubbers	Flue gas desulfurization emissions controls.
SEC	United States Securities and Exchange Commission.
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.
spark spread	The difference between power prices and natural gas fuel costs.
Stone & Webster	Stone & Webster, Inc.
swaption	An option that grants the holder the right, but not the obligation, to enter into the underlying swap.
Total margin capture factor	The actual gross margin for a unit from energy, and contracted and capacity divided by the total gross margin from energy, and contracted and capacity that could have been earned by the unit.
VaR	Value at risk.
VIE	Variable interest entity.
WCI	Western Climate Initiative.

Table of Contents

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, intend, seek, plan, 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 such as coal and natural gas 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, including financial 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;

Table of Contents

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 losses from open positions;

volatility in our gross margin as a result of changes in the fair value of our 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;

Table of Contents

- 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. and its consolidated subsidiaries, after giving effect to the Merger.

PART I

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	September 30, Three Months Ended 2011	September 30, September 30, 2010	September 30, Nine Months Ended 2011	September 30, September 30, 2010
	(in millions, except per share data) (See notes 1 and 2 on the Merger)			
Operating revenues (including unrealized gains (losses) of $49 million, $154 million, $(86) million and $286 million, respectively)	$ 1,080	$ 775	$ 2,706	$ 1,899
Cost of fuel, electricity and other products (including unrealized (gains) losses of $11 million, $(13) million, $(27) million and $107 million, respectively)	526	247	1,317	726
Gross Margin (excluding depreciation and amortization)	554	528	1,389	1,173
Operating Expenses:				
Operations and maintenance	286	172	963	470
Depreciation and amortization	94	53	265	157
Impairment losses	133		133	
Gain on sales of assets, net	(6)	(1)	(5)	(4)
Total operating expenses	507	224	1,356	623
Operating Income	47	304	33	550
Other Income (Expense), net:				
Interest expense	(86)	(51)	(291)	(150)
Interest income	1		1	
Other, net	1	1	(21)	(1)
Total other expense, net	(84)	(50)	(311)	(151)
Income (Loss) Before Income Taxes	(37)	254	(278)	399
Provision for income taxes	1		4	1
Net Income (Loss)	$ (38)	$ 254	$ (282)	$ 398
Basic and Diluted EPS:				
Basic EPS	$ (0.05)	$ 0.62	$ (0.36)	$ 0.97
Diluted EPS	$ (0.05)	$ 0.62	$ (0.36)	$ 0.96

Weighted average shares outstanding	772	413	771	412
Effect of dilutive securities				1
Weighted average shares outstanding assuming dilution	772	413	771	413

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

1

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, September 30, 2011	September 30, December 31, 2010
	(in millions) (See notes 1 and 2 on the Merger)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,746	$ 2,402
Funds on deposit	403	1,834
Receivables, net	325	538
Derivative contract assets	711	1,420
Inventories	525	553
Prepaid expenses and other current assets	155	155
Total current assets	3,865	6,902
Property, plant and equipment, gross	7,291	7,226
Accumulated depreciation and amortization	(1,099)	(977)
Property, Plant and Equipment, net	6,192	6,249
Noncurrent Assets:		
Intangible assets, net	49	140
Derivative contract assets	549	716
Deferred income taxes	208	353
Prepaid rent	374	348
Other	477	503
Total noncurrent assets	1,657	2,060
Total Assets	$ 11,714	$ 15,211
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 9	$ 2,061
Accounts payable and accrued liabilities	680	903
Derivative contract liabilities	550	1,227
Deferred income taxes	208	353
Other	126	132
Total current liabilities	1,573	4,676
Noncurrent Liabilities:		
Long-term debt, net of current portion	4,066	4,020
Derivative contract liabilities	95	189
Pension and postretirement obligations	171	171
Other	645	672
Total noncurrent liabilities	4,977	5,052

Commitments and Contingencies				
Stockholders Equity:				
Preferred stock, par value $.001 per share, authorized 125,000,000 shares, no shares issued at September 30, 2011 and December 31, 2010				
Common stock, par value $.001 per share, authorized 2.0 billion shares, issued 771,690,694 shares and 770,857,530 shares at September 30, 2011 and December 31, 2010, respectively		1		1
Additional paid-in capital		7,446		7,432
Accumulated deficit		(2,207)		(1,925)
Accumulated other comprehensive loss		(76)		(25)
Total stockholders equity		5,164		5,483
Total Liabilities and Stockholders Equity	$	11,714	$	15,211

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

Table of Contents

GENON ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2011	2010
	(in millions) (See notes 1 and 2 on the Merger)	
Cash Flows from Operating Activities:		
Net income (loss)	$ (282)	$ 398
Adjustments to reconcile net income (loss) and changes in other operating assets and liabilities to net cash provided by operating activities:		
Depreciation and amortization	277	160
Impairment losses	133	
Amortization of acquired contracts	(25)	
Gain on sales of assets, net	(5)	(4)
Net changes in derivative contracts	59	(179)
Stock-based compensation expense	11	13
Postretirement benefits curtailment gain		(37)
Lower of cost or market inventory adjustments	2	22
Loss on early extinguishment of debt	23	
Other, net	(2)	
Funds on deposit	4	(105)
Changes in other operating assets and liabilities	87	75
Total adjustments	564	(55)
Net cash provided by operating activities of continuing operations	282	343
Net cash provided by operating activities of discontinued operations		6
Net cash provided by operating activities	282	349
Cash Flows from Investing Activities:		
Capital expenditures	(328)	(214)
Proceeds from the sales of assets	18	4
Restricted funds on deposit, net	1,396	(33)
Other, net		2
Net cash provided by (used in) investing activities	1,086	(241)
Cash Flows from Financing Activities:		
Repayment of long-term debt	(2,075)	(71)
Proceeds from long-term debt	50	
Other, net	1	(1)
Net cash used in financing activities	(2,024)	(72)
Net Increase (Decrease) in Cash and Cash Equivalents	(656)	36
Cash and Cash Equivalents, beginning of period	2,402	1,953
Cash and Cash Equivalents, end of period	$ 1,746	$ 1,989

Supplemental Disclosures:		
Cash paid for interest, net of amounts capitalized	$ 225	$ 94
Cash paid for income taxes (net of refunds received)	$ (6)	$ 2

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

Table of Contents

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. During the three months ended September 30, 2011, we recorded interim revisions to the provisional allocation of the purchase price at December 3, 2010 and accordingly revised amounts in our consolidated balance sheet at December 31, 2010 and our consolidated statements of operations for 2010 and the three and six months ended June 30, 2011. See note 2 for additional information on the Merger and these revisions.

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 September 30, 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 13 for further discussion of MC Asset Recovery.

Table of Contents

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;
- estimating 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.

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.

Table of Contents

Funds on Deposit

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

		September 30, September 30, 2011		September 30, December 31, 2010
		(in millions)		
Cash collateral posted energy trading and marketing	$	194	$	220
Cash collateral posted other operating activities[1]		39		45
Cash collateral posted surety bonds[2]		34		34
GenOn Mid-Atlantic restricted cash[3]		166		
GenOn Marsh Landing development project cash collateral posted[4]		134		106
Environmental compliance deposits[5]		33		32
Funds deposited with the trustee to discharge the GenOn senior secured notes, due 2014[6]				285
Funds deposited with the trustee to defease the PEDFA fixed-rate bonds, due 2036[6]				394
Funds deposited with the trustee to discharge the GenOn North America senior notes, due 2013[6]				866
Other		22		40
Total current and noncurrent funds on deposit		622		2,022
Less: Current funds on deposit		403		1,834
Total noncurrent funds on deposit	$	219	$	188

(1) 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 and note 5).

(2) Represents cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations.

(3) Represents cash reserved in respect of interlocutory liens related to the scrubber contract litigation. See note 13.

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

(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 13 for our obligations related to ash landfill sites and site contamination remediation.

(6) See note 7 for discussion of the related debt.

Inventories

Inventories were comprised of the following:

		September 30, September 30, 2011		September 30, December 31, 2010
		(in millions)		
Fuel inventory:				
Coal	$	187	$	153
Fuel oil		112		169
Natural gas				1
Other		4		1
Materials and supplies		199		194
Purchased emissions allowances		23		35

Total inventories	$	525	$	553

During the three months ended September 30, 2011 and 2010, we recorded $1 million and $2 million, respectively, and during the nine months ended September 30, 2011 and 2010, we recorded $2 million and $22 million, respectively, for lower of average cost or market valuation adjustments in cost of fuel, electricity and other products.

6

Table of Contents

Capitalization of Interest Cost

We incurred the following interest costs:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)			
Total interest costs	$ 91	$ 52	$ 301	$ 154
Capitalized and included in property, plant and equipment, net	(5)	(1)	(10)	(4)
Interest expense	$ 86	$ 51	$ 291	$ 150

The amounts of capitalized interest above include interest accrued. During the three months ended September 30, 2011 and 2010, cash paid for interest was $16 million and $2 million, respectively, of which $4 million and $0, respectively, were capitalized. During the nine months ended September 30, 2011 and 2010, cash paid for interest was $234 million and $97 million, respectively, of which $9 million and $3 million, respectively, were capitalized.

Income Taxes

At September 30, 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 September 30, 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 6 for additional information on fair value measurements.

New Accounting Guidance Not Yet Adopted at September 30, 2011

Fair Value Measurement and Disclosure. In May 2011, the FASB issued new fair value measurement and disclosure guidance. The new standard does not extend the use of fair value but rather provides guidance about how fair value should be determined and requires additional disclosures. The guidance is not expected to have a material effect on our fair value measurements, but will require disclosure of the following:

- quantitative information about the unobservable inputs used in a fair value measurement that is categorized within Level 3 of the fair value hierarchy;
- for those fair value measurements categorized within Level 3 of the fair value hierarchy, both the valuation processes used and the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any; and
- the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed.

We will present the additional disclosures as required in our Form 10-Q for the quarter ended March 31, 2012.

7

Table of Contents

Comprehensive Income. In June 2011, the FASB issued guidance that revises the manner in which companies present comprehensive income in their financial statements. The guidance requires companies to report the components of comprehensive income in either (a) a continuous statement of comprehensive income or (b) two separate but consecutive statements. The guidance does not change the items that must be reported in comprehensive income. We will update our presentation as required in our Form 10-Q for the quarter ended March 31, 2012.

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 September 30, 2011 and December 31, 2010 are property, plant and equipment, intangible assets and long-term liabilities related to out-of-market contracts, certain contingencies and taxes. 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 the fourth quarter of 2011.

Table of Contents

The provisional allocation of the purchase price is as follows at September 30, 2011 (in millions):

		September 30,
Cash and cash equivalents	$	717
Current derivative contract assets		156
Inventories		275
Other current assets		305
Property, plant and equipment		3,090[(1)]
Intangible assets		47
Other noncurrent assets		260
Current derivative contract liabilities		(100)
Other current liabilities		(446)
Long-term debt		(1,931)
Pension and postemployment obligations		(105)
Other noncurrent liabilities		(579)
Estimated fair value of net assets acquired		1,689
Purchase price		1,305[(2)]
Gain on bargain purchase	$	384[(3)(4)]

(1) The valuations of the acquired long-lived assets were primarily based on the income approach, and in particular, discounted cash flow analyses. The income approach was employed for the generating facilities because of the differing age, geographic location, market conditions, asset lives, equipment condition and status of environmental controls of the assets. The discounted cash flows incorporated information based on observable market prices to the extent available and long-term prices derived from proprietary fundamental market modeling. For the generating facilities that were not valued using the income approach, the cost approach was used. The market approach was considered, but was ultimately given no weighting because of many of the factors listed as the primary reasons for application of the income approach as well as a lack of proximity of the observed transactions to the valuation date.

(2) Because the Merger is accounted for as a reverse acquisition with Mirant as the accounting acquirer (see note 1, Basis of Presentation section), the purchase price was computed based on shares of Mirant common stock that would have been issued to RRI Energy s stockholders on the date of the Merger to give RRI Energy an equivalent ownership interest in Mirant as it had in the combined company (approximately 46%). See note 2 to our consolidated financial statements in our 2010 Annual Report on Form 10-K for information regarding computation of total purchase price.

(3) The gain on the bargain purchase was recorded in other income in the consolidated statement of operations during 2010. For information regarding factors contributing to the gain on bargain purchase, see note 2 to our consolidated financial statements in our 2010 Annual Report on Form 10-K.

(4) The acquisition is treated as a nontaxable merger for federal income tax purposes and there is no tax deductible goodwill resulting from the Merger.

Table of Contents

The above allocation of the purchase price includes interim revisions to the provisional allocation that was reported at June 30, 2011, March 31, 2011 and December 31, 2010 primarily for property, plant and equipment, intangible assets and long-term liabilities related to out-of-market contracts, certain contingencies and asset retirement obligations, which reduced the gain on bargain purchase by $134 million recognized during 2010. Our consolidated balance sheet at December 31, 2010 has been retroactively amended for the revisions to the provisional allocation as follows:

	September 30, Increase/ (Decrease) (in millions)
Current Assets:	
Total current assets	$ 1
Property, Plant and Equipment, net	(49)
Noncurrent Assets:	
Intangible assets, net	(4)
Other	(11)
Total noncurrent assets	(15)
Total Assets	$ (63)
Current Liabilities:	
Total current liabilities	$ (9)
Noncurrent Liabilities:	
Other	80
Total noncurrent liabilities	80
Stockholders Equity:	
Accumulated deficit	(134)
Total stockholders equity	(134)
Total Liabilities and Stockholders Equity	$ (63)

Our results of operations have been retroactively amended for the interim revisions to the provisional allocation as follows: (a) for the six months ended June 30, 2011, our net loss decreased by $7 million and (b) for the year ended December 31, 2010, the gain on bargain purchase decreased by $134 million and net loss increased by the same amount. The impacts on our results of operations for 2010, other than the gain on bargain purchase, as a result of the revisions to the provisional allocation were not material.

We are subject to material contingencies, some of which may involve substantial amounts, relating to (a) pending natural gas litigation, (b) environmental matters, (c) CenterPoint indemnity, (d) Texas franchise tax audit, (e) sales tax contingencies, (f) refund contingency related to transportation rates and (g) income tax contingencies. For information regarding these contingencies, see note 13. As a result of the number of variables and assumptions involved in assessing the possible outcome of these matters, sufficient information does not exist to reasonably estimate the fair value or a range of outcomes for these contingent liabilities, except as disclosed in note 13. Unless otherwise noted in note 13, we cannot predict the outcome of the matters. These material contingencies have been evaluated in accordance with the accounting guidance for contingencies, and no provisional amounts for these matters have been recorded at the date of the Merger because the recognition criteria have not been met, except as denoted in note 13.

Table of Contents

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):

		September 30,
Balance, January 1, 2011	$	30(1)
Accrued and expensed		61(2)
Paid		(62)
Balance, September 30, 2011	$	29(1)

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

(2) Includes $39 million of charges associated with employee severance, $5 million of charges related to corporate facilities lease impairment and $17 million of charges related to integration and other activities.

4. Comprehensive Income (Loss)

The components of comprehensive income (loss) are:

	September 30, Three Months Ended September 30, 2011	September 30, Three Months Ended September 30, 2010	September 30, Nine Months Ended September 30, 2011	September 30, Nine Months Ended September 30, 2010
	(in millions)			
Net income (loss)	$ (38)	$ 254	$ (282)	$ 398
Pension and other postretirement benefits		(1)		4
Deferred loss from cash flow hedges interest rate swaps	(39)		(50)	
Unrealized losses on available-for-sale securities			(1)	
Total comprehensive income (loss)	$ (77)	$ 253	$ (333)	$ 402

5. Impairment of Long-Lived Assets and Emissions Allowances

We evaluate long-lived assets, such as property, plant and equipment and purchased intangible assets subject to amortization, for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. Such evaluations are performed in accordance with the accounting guidance related to evaluating long-lived assets for impairment. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to the estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future cash flows, an impairment charge is recognized as the amount by which the carrying amount of the asset exceeds its fair value.

Granted Emissions Credits

In August 2011, the EPA finalized the regulations to replace the CAIR with the CSAPR starting in 2012. The CSAPR addresses interstate transport of emissions of NO_x and SO_2. The CSAPR establishes limitations on NO_x and/or SO_2 emissions from electric generating units that are (i) greater than 25 megawatts and (ii) located in 27 states (in the eastern half of the United States) that the EPA determined contribute significantly to nonattainment in other states, or to interfere with maintenance in other states, of one or more of three NAAQS: (a) the annual NAAQS for fine particulate matter ($PM_{2.5}$) promulgated in 1997; (b) the 24-hour NAAQS for $PM_{2.5}$ promulgated in 2006 and (c) the ozone NAAQS promulgated in 1997. The CSAPR creates emission budgets for each of the covered states and allocates emissions allowances (denominated in tons of emissions) to each of the 27 states regulated under the CSAPR. Under the EPA federal implementation plan, for 2012, we were allocated 31,901, 14,724, and 78,129 allowances under the CSAPR for annual NO_x, ozone-season NO_x, and SO_2, respectively. The federal implementation plan has also outlined EPA-determined allocations in the same amounts for 2013, although the CSAPR contemplates that states after 2012 may allocate allowances in a different manner than allocated initially under the CSAPR. In October 2011, the EPA proposed revisions to the final CSAPR that, if finalized, would

Table of Contents

provide us with a small allowance increase in each compliance year. As a result, our expected CSAPR allowances would be 31,944, 14,768 and 78,193 in 2012, and 31,979, 14,785 and 78,331 in 2013, for annual NO_x, ozone-season NO_x and SO_2, respectively. The CSAPR limits each electric generating unit s NO_x and SO_2 emissions to amounts covered by the number of allowances held by that source in allowance accounts under the program (which may be purchased or otherwise acquired from other sources, subject to certain limitations in the rule). The NO_x allowances from the CAIR program will not be used in the CSAPR program and accordingly will have no value after 2011. The SO_2 allowances used for compliance in the CAIR program are the acid rain program allowances, which will have negligible value after 2011. As a result of the CSAPR, we recorded impairment losses of $133 million for (a) the write-off of excess NO_x and SO_2 emissions allowances included in intangible assets ($75 million) and (b) the write-off of excess NO_x and SO_2 emissions allowances previously included in property, plant and equipment ($58 million) during the three months ended September 30, 2011. The emissions allowances within property, plant and equipment and intangible assets had previously been included with a generating facility asset group for purposes of impairment testing. As (a) there will be no future use of the NO_x emissions allowances and (b) the SO_2 emission allowances will have negligible value after 2011 under the CSAPR and their price has fallen sharply, we evaluated, in conjunction with preparing these interim financial statements, these emissions allowances for impairment separately from the generating facility asset group and determined that impairments existed.

CAIR NO_x emissions allowances of $45 million will have no value after 2011, and were therefore fully impaired. The excess acid rain program SO_2 emissions allowances of $91 million will have negligible value after 2011 and were impaired to their estimated fair value of $3 million based on their current market prices obtained from brokers. The excess acid rain program SO_2 emissions allowances were categorized in Level 3 in the fair value hierarchy.

Potomac River Retirement

In the fourth quarter of 2010, we recorded impairment losses of $42 million to reduce the carrying value of the Potomac River generating facility to its estimated fair value of approximately $1 million. In addition, as a result of the impairment of the Potomac River generating facility, we recorded $32 million in operations and maintenance expense and corresponding liabilities associated with our commitment to reduce particulate emissions as part of the agreement with the City of Alexandria, Virginia. This $32 million is held in an escrow account. The planned capital investment would not be recovered in future periods based on the current projected cash flows of the Potomac River generating facility. See note 5(c) to our consolidated financial statements in our 2010 Annual Report on Form 10-K for further discussion.

In August 2011, we entered into an agreement with the City of Alexandria, Virginia to remove permanently from service our Potomac River generating facility. The agreement, which amends our Project Schedule and Agreement, dated July 17, 2008 with the City of Alexandria, provides for the retirement of the Potomac River generating facility on October 1, 2012, subject to the receipt of all necessary consents and approvals. PJM has determined that the retirement of the facility will not affect reliability. We must now receive consent from PEPCO. We will reverse the previously recorded obligation upon the receipt of consent from PEPCO and we will recognize a reduction in operations and maintenance expense. If the PEPCO consent has not been received by July 3, 2012, the Potomac River generating facility will be retired within 90 days after the receipt thereof. Upon retirement of the Potomac River generating facility, all funds in the escrow account ($32 million) established under the July 17, 2008 agreement shall be distributed to us, provided, that, if the retirement of the facility is after January 1, 2014, $750,000 of such funds shall be paid to the City of Alexandria.

6. 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. Through our asset management activities, we enter into a variety of exchange-traded and OTC energy and energy-related derivative financial instruments, such as forward contracts, futures contracts, option contracts and financial swap agreements to manage 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 nine months ended September 30, 2011 or during 2010.

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.

Table of Contents

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

	September 30, Derivative Contract Assets Current	September 30, Derivative Contract Assets Long-Term	September 30, Derivative Contract Liabilities Current	September 30, Derivative Contract Liabilities Long-Term	September 30, Net Derivative Contract Assets (Liabilities)
			(in millions)		
September 30, 2011					
Commodity Contracts:					
Asset management	$ 365	$ 529	$ (198)	$ (52)	$ 644
Trading activities	346	20	(351)	(17)	(2)
Total commodity contracts	711	549	(549)	(69)	642
Interest Rate Contracts			(1)	(26)	(27)
Total derivatives	$ 711	$ 549	$ (550)	$ (95)	$ 615
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

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

Derivatives Not Designated as Hedging Instruments	September 30, Three Months Ended September 30, 2011 Operating Revenues	September 30, 2011 Cost of Fuel, Electricity and Other Products	September 30, 2010 Operating Revenues	September 30, 2010 Cost of Fuel, Electricity and Other Products
		(in millions)		
Asset Management Commodity Contracts:				
Unrealized	$ 38	$ (11)	$ 164	$ 13
Realized[(1)(2)]	54	(27)	54	(69)
Total asset management	$ 92	$ (38)	$ 218	$ (56)
Trading Commodity Contracts:				
Unrealized	$ 11	$	$ (10)	$
Realized[(1)(2)]	(13)			
Total trading	$ (2)	$	$ (10)	$

Total derivatives	$ 90	$ (38)	$ 208	$ (56)

(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.

Table of Contents

	Nine Months Ended September 30, 2011		Nine Months Ended September 30, 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	$ (85)	$ 27	$ 299	$ (107)
Realized[1][2]	194	(84)	230	(95)
Total asset management	$ 109	$ (57)	$ 529	$ (202)
Trading Commodity Contracts:				
Unrealized	$ (1)	$	$ (13)	$
Realized[1][2]	(8)		(2)	
Total trading	$ (9)	$	$ (15)	$
Total derivatives	$ 100	$ (57)	$ 514	$ (202)

(1) Represents the total cash settlements of derivative financial instruments during each reporting period (composed of the sum of the quarterly settlements) 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 comprehensive income/loss during the three and nine months ended September 30, 2011 (amount of gain (loss)):

Recognized in OCI on Interest Rate Derivatives[1] (in millions)	Location of Gain (Loss) Recognized in Income/Loss	Reclassified from Accumulated OCI into Earnings[1]	Recognized in Earnings on Derivatives[2][3]
Three Months Ended September 30, 2011:			
$(39)	Interest expense	$	$
Nine Months Ended September 30, 2011:			
$(50)	Interest expense	$	$

(1) OCI is other comprehensive income.

(2) 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 gain of $4 million during the three and nine months ended September 30, 2011 and was recorded in interest expense.

(3) 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 September 30, 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. At September 30, 2011, the accumulated other comprehensive loss balance was $29 million. 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 during the construction period 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.

Table of Contents

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

	September 30,	September 30,	September 30,
	Notional Volumes at September 30, 2011		
Derivative Instruments	**Derivative Contract Assets**	**Derivative Contract Liabilities (in millions)**	**Net Derivative Contracts**
Commodity Contracts (in equivalent MWh):			
Power(1)	(69)	18	(51)
Natural gas	(17)	19	2
Fuel oil	(1)	1	
Coal	6	10	16
Interest Rate Contracts (in dollars)(2)		475	475

	September 30,	September 30,	September 30,
	Notional Volumes at December 31, 2010		
Derivative Instruments	**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) When Marsh Landing commences commercial operation 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 estimating 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.

Most of the fair value of our derivative contract assets and liabilities is based 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. At September 30, 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 estimate 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 September 30, 2011, the assets and liabilities classified as Level 3 in the fair value hierarchy represented approximately 4% of total derivative contract assets and 13% of total derivative contract liabilities.

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.

Table of Contents

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.

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

	September 30,	September 30,	September 30,	September 30,
	September 30, 2011			
	Level 1[(1)]	Level 2[(1)(2)]	Level 3	Total Fair Value
	(in millions)			
Derivative contract assets:				
Commodity Contracts				
Asset Management:				
Power	$ 30	$ 828	$ 6	$ 864
Fuel	4	2	24	30
Total Asset Management	34	830	30	894
Trading Activities	202	148	16	366
Interest Rate Contracts				
Total derivative contract assets	$ 236	$ 978	$ 46	$ 1,260
Derivative contract liabilities:				
Commodity Contracts				
Asset Management:				
Power	$ 19	$ 137	$ 5	$ 161
Fuel	17	1	71	89
Total Asset Management	36	138	76	250
Trading Activities	213	145	10	368
Interest Rate Contracts		27		27
Total derivative contract liabilities	$ 249	$ 310	$ 86	$ 645
Interest-bearing funds[(3)]	$ 2,089	$	$	$ 2,089
Other assets[(4)]	$ 20	$	$	$ 20

(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 nine months ended September 30, 2011.
(2) Option contracts comprised approximately 3% of net derivative contract assets.
(3) Represents investments in money market funds and is included in cash and cash equivalents, funds on deposit and other noncurrent assets in the consolidated balance sheet. We had $1.722 billion of interest-bearing funds included in cash and cash equivalents, $174 million included in funds on deposit and $193 million included in other noncurrent assets.
(4) Relates to mutual funds held in a rabbi trust for non-qualified deferred compensation plans for some key and highly compensated employees.

Table of Contents

	September 30, Level 1[1]	September 30, December 31, 2010 Level 2[1][2] (in millions)	September 30, Level 3	September 30, Total Fair Value
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 is 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 mutual funds held in a rabbi trust for non-qualified deferred compensation plans for some key and highly compensated employees.

The following is a reconciliation of changes (composed of the sum of the quarterly changes) in fair value of net commodity derivative contract assets and liabilities classified as Level 3 during the nine months ended September 30, 2011 and 2010, respectively:

	September 30,	September 30,	September 30,
	Net Derivatives Contracts (Level 3)		
	Asset Management	Trading Activities (in millions)	Total
Balance, January 1, 2011 (net asset (liability))	$ (70)	$ 2	$ (68)
Total gains (losses) realized/unrealized:			
Included in earnings [(1)]	5	9	14
Purchases[(2)]			
Issuances[(2)]			
Settlements[(3)]	7	(5)	2
Transfers into Level 3[(4)]			
Transfers out of Level 3[(4)]	12		12
Balance, September 30, 2011 (net asset (liability))	$ (46)	$ 6	$ (40)
Balance, January 1, 2010 (net asset (liability))	$ 19	$ 13	$ 32
Total gains (losses) realized/unrealized:			
Included in earnings [(1)]	(45)	(22)	(67)
Purchases[(2)]			
Issuances[(2)]			
Settlements[(5)]	(80)	28	(52)
Transfers in and out of Level 3[(4)]	38	(1)	37
Balance, September 30, 2010 (net asset (liability))	$ (68)	$ 18	$ (50)

(1) Represents the fair value, as of the end of each reporting period, of Level 3 contracts entered into during each reporting period and the gains and losses attributable to Level 3 contracts that existed as of the beginning of each reporting period and were still held at the end of each reporting period.
(2) Contracts entered into during each 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 reporting period.
(4) Denotes the total contracts that existed at the beginning of each reporting period and were still held at the end of each 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 reporting period. Amounts reflect fair value as of the end of each reporting period.
(5) Represents the total cash settlements of contracts during each reporting period that existed at the beginning of each reporting period.

The following table presents the amounts included in income related to derivative contract assets and liabilities classified as Level 3:

September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
Three Months Ended September 30,					
	2011			2010	
Operating Revenues	Cost of Fuel,	Total	Operating Revenues	Cost of Fuel,	Total

	Electricity and Other Products		(in millions)	Electricity and Other Products		
Gains (losses) included in income	$ (3)	$ (10)	$ (13)	$ (1)	$ 24	$ 23
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 September 30	$ (2)	$ (11)	$ (13)	$ (1)	$ 24	$ 23

Table of Contents

	Nine Months Ended September 30, 2011 Operating Revenues	2011 Cost of Fuel, Electricity and Other Products	2011 Total	2010 Operating Revenues	2010 Cost of Fuel, Electricity and Other Products	2010 Total
	(in millions)					
Gains (losses) included in income	$ 3	$ 25	$ 28	$ 1	$ (83)	$ (82)
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 September 30	$ 5	$ 23	$ 28	$ 6	$ (83)	$ (77)

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 valuation adjustment on derivative contract assets was $52 million and $21 million at September 30, 2011 and December 31, 2010, respectively.

At September 30, 2011 and December 31, 2010, $3 million of cash collateral posted to us by counterparties under master netting agreements was 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:

Credit Rating Equivalent	September 30, 2011 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	$ 484	$ 62	$ 62	$	
Investment Grade:					
Financial institutions	742	691		691	71%
Energy companies	327	211	2	209	21%
Non-investment Grade:					
Energy companies	15	11	1	10	1%
No External Ratings:					
Internally-rated investment grade	40	40	1	39	4%
Internally-rated non-investment grade	26	24		24	3%
Total	$ 1,634	$ 1,039	$ 66	$ 973	100%

Table of Contents

Credit Rating Equivalent	September 30, Gross Exposure Before Collateral(1)	September 30, Net Exposure Before Collateral(2)	September 30, December 31, 2010 Collateral(3) (dollars in millions)	September 30, Exposure Net of Collateral	September 30, % of Net Exposure
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 September 30, 2011 and three investment grade counterparties at December 31, 2010, respectively, each representing an exposure of more than 10% of total credit exposure, net of collateral and totaling $586 million and $716 million at September 30, 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 September 30, 2011, the fair value of financial instruments with credit-risk-related contingent features in a net liability position was $43 million for which we had posted collateral of $34 million, including cash and letters of credit.

At September 30, 2011 and December 31, 2010, we had $96 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.

Table of Contents

The carrying amounts and fair values of financial instruments are as follows:

	September 30, September 30, 2011 Carrying Amount	September 30, Fair Value	September 30, December 31, 2010 Carrying Amount	September 30, Fair Value
	(in millions)			
Liabilities:				
Long and short-term debt[(1)]	$ 4,075	$ 3,843	$ 6,081	$ 6,117

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

7. Long-Term Debt

Outstanding debt was as follows:

	September 30, Weighted Average Stated Interest Rate [(1)]	September 30, September 30, 2011 Long-term	September 30, Current	September 30, Weighted Average Stated Interest Rate [(1)]	September 30, December 31, 2010 Long-term	September 30, 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	686	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		(25)	(2)		(27)	(2)
GenOn Americas Generation:						
Senior unsecured notes, due 2011[(5)]				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[(6)]				7.375		850

GenOn Marsh Landing:						
Senior secured term loan, due 2017[7]	2.70	15				
Senior secured term loan, due 2023[7]	2.95	35				
Other:						
Capital leases, due 2011 to 2015	7.375-8.19	15	4	7.375-8.19	18	4
PEDFA fixed-rate bonds, due 2036[8]				6.75		371
Adjustment to fair value of debt[9]		(33)			(35)	17
Total		$ 4,066	$ 9		$ 4,020	$ 2,061

(1) The weighted average stated interest rates are at September 30, 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 10.25% for senior unsecured notes due 2018 and 2020, respectively.

(5) These notes were repaid on May 2, 2011.

(6) 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.

(7) During the second quarter of 2011, we satisfied the required initial equity contributions of $147 million and GenOn Marsh Landing began borrowing under its credit facility.

(8) These notes were defeased at 103% of principal plus accrued and unpaid interest to the redemption date of June 1, 2011 and were redeemed on that day.

(9) Debt assumed in the Merger was adjusted to fair value on the Merger date. Included in interest expense is amortization of $0 and $2 million for valuation adjustments related to the assumed debt for the three and nine months ended September 30, 2011, respectively.

Table of Contents

GenOn Credit Facilities

Availability of borrowings under the GenOn revolving credit facility is reduced by any outstanding letters of credit. At September 30, 2011, outstanding letters of credit were $239 million and availability of borrowings under the revolving credit facility was $549 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 unsecured notes, dated October 4, 2010, we filed a registration statement and completed, in the second quarter of 2011, offerings to exchange the old notes for a like principal amount at maturity of new notes. The new notes have the same terms and conditions as the old notes, including interest rates, maturity dates and covenants.

At September 30, 2011, GenOn Energy did not meet the consolidated debt ratio component of the restricted payments test under the terms of its senior notes and, therefore, the ability of GenOn Energy to make restricted payments is limited to specified exclusions from the covenant, including up to $250 million of such restricted payments.

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 a $1 million loss on early 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 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 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 early 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.

PEDFA Fixed-Rate Bonds

The PEDFA bonds (issued in 2004) were recorded at their fair value on the Merger date which approximated their redemption value. Upon the closing of the Merger, the PEDFA bonds were defeased 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 $394 million at December 31, 2010 and was recorded as restricted cash and included in the funds on deposit on the consolidated balance sheet.

Table of Contents

On June 1, 2011, the PEDFA bonds were redeemed at the call price of 103% of the principal amount plus accrued and unpaid interest through the date of redemption. The total payment on the date of redemption was $394 million and a $1 million gain on extinguishment of debt was recognized during the three months ended June 30, 2011.

8. 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, and 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:

		September 30,	September 30,
		September 30, 2011	December 31, 2010
		(in millions)	
Letters of credit	Marsh Landing development project[1]	$ 178	$ 106
Letters of credit	rent reserves	103	133
Letters of credit	energy trading and marketing activities	57	96
Letters of credit	other operating activities	35	38
Surety bonds[2]		42	50
Total		$ 415	$ 423

(1) Includes $134 million and $106 million of cash-collateralized letters of credit at September 30, 2011 and December 31, 2010, respectively.
(2) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at September 30, 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.

Table of Contents

9. Pension and Other Postretirement Benefit Plans

We have various defined benefit pension plans, other postretirement benefit plans and defined contribution savings 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:

	September 30,	September 30,	September 30,	September 30,
	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Service cost	$ 3	$ 2	$	$
Interest cost	5	4	1	
Expected return on plan assets	(7)	(5)		
Net amortization(1)	1		(1)	(1)
Net periodic benefit cost (credit)	$ 2	$ 1	$	$ (1)

	September 30,	September 30,	September 30,	September 30,
	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Service cost	$ 9	$ 6	$	$
Interest cost	17	12	3	2
Expected return on plan assets	(22)	(16)		
Net amortization(1)	3	1	(3)	(5)
Curtailments				(37)
Net periodic benefit cost (credit)	$ 7	$ 3	$	$ (40)

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

Table of Contents

Immaterial Misstatement of Post-Employment Benefits in Prior Periods

During the second quarter of 2011, we identified an under accrual of post-employment benefits relating to over ten years up to and through 2010. In those years, we did not recognize a liability for future expected costs of benefits for inactive employees who were unable to perform services because of a disability. For 2010, 2009, 2008, 2007 and 2006, our operations and maintenance expense was understated by $0, $1 million, $1 million, $1 million and $2 million, respectively. Our net income/loss for these years was misstated by the same amounts. The misstatements had no effect on cash flows for any of the periods.

To correct the misstatements, we recorded the following immaterial adjustments to the prior period financial statements presented in this Form 10-Q: (a) cumulative increase to accumulated deficit and decrease to stockholders equity of $13 million in the consolidated balance sheet at December 31, 2010 and (b) cumulative increase to other long-term liabilities and total noncurrent liabilities of $13 million in the consolidated balance sheet at December 31, 2010.

10. Stock-Based Compensation

Compensation expense for the stock-based incentive plans was:

	September 30, Three Months Ended September 30, 2011	September 30, September 30, 2010	September 30, Nine Months Ended September 30, 2011	September 30, September 30, 2010
	(in millions)			
Stock-based incentive plans compensation expense (pre-tax)(1)(2)	$ 3	$ 5	$ 11	$ 13

(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 nine months ended September 30, 2011 and 2010 because of our NOL carryforwards.

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 a multiplier between 0% and 200% of the targeted grant; vest ratably each year over three-year period; settled in common stock
Nonqualified Stock Options	4,118,280	Time-based; vest ratably each year over three-year period

11. 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 and nine months ended September 30, 2010 retroactively adjusted to give effect to the Exchange Ratio and include the combined entities for the three and nine months ended September 30, 2011.

Table of Contents

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions, except per share data)			
Net income (loss)	$ (38)	$ 254	$ (282)	$ 398
Basic and diluted shares:				
Weighted average shares outstanding basic	772	413	771	412
Shares from assumed vesting of restricted stock units	[1]		[1]	1
Weighted average shares outstanding diluted	772	413	771	413
Basic and Diluted EPS:				
Basic EPS	$ (0.05)	$ 0.62	$ (0.36)	$ 0.97
Diluted EPS	$ (0.05)	$ 0.62	$ (0.36)	$ 0.96

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

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 September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)			
Series A Warrants[1]		76		76
Series B Warrants[1]		20		20
Restricted stock units	5	3	5	3
Stock options	17	12	18	12
Total number of antidilutive shares	22	111	23	111

(1) These warrants expired January 3, 2011.

12. 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

Table of Contents

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.

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

	00000000	00000000	00000000	00000000	00000000	00000000	00000000
	Eastern PJM	**Western PJM/MISO**	**California**	**Energy Marketing (in millions)**	**Other Operations**	**Eliminations**	**Total**
Three Months Ended September 30, 2011:							
Operating revenues[1]	$ 346	$ 433	$ 128	$ 88	$ 85	$	$ 1,080
Cost of fuel, electricity and other products[2]	179	206	11	71	59		526
Gross margin (excluding depreciation and amortization)	167	227	117	17	26		554
Operating Expenses:							
Operations and maintenance	99	108	33		46[3]		286
Depreciation and amortization	34	27	11	1	21		94
Impairment losses[4]	95	4	14		20		133
Gain on sales of assets, net			(5)		(1)		(6)
Total operating expenses	228	139	53	1	86		507
Operating income (loss)	$ (61)	$ 88	$ 64	$ 16	$ (60)	$	$ 47

(1) Includes unrealized gains (losses) of $(2) million, $37 million, $1 million, $15 million and $(2) million for Eastern PJM, Western PJM/MISO, California, Energy Marketing and Other Operations, respectively.
(2) Includes unrealized (gains) losses of $10 million, $1 million, $(1) million and $1 million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.
(3) Includes $24 million of merger-related costs.
(4) Represents impairment losses for the write off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR. See note 5.

Table of Contents

	00000000	00000000	00000000	00000000	00000000	00000000	00000000
	Eastern PJM	**Western PJM/MISO**	**California**	**Energy Marketing (in millions)**	**Other Operations**	**Eliminations**	**Total**
Nine Months Ended September 30, 2011:							
Operating revenues[1]	$ 962	$ 1,050	$ 200	$ 292	$ 202	$	$ 2,706
Cost of fuel, electricity and other products[2]	433	526	14	222	122		1,317
Gross margin (excluding depreciation and amortization)	529	524	186	70	80		1,389
Operating Expenses:							
Operations and maintenance	351	368	111	2	131[3]		963
Depreciation and amortization	101	81	32	2	49		265
Impairment losses[4]	95	4	14		20		133
Gain on sales of assets, net			(5)				(5)
Total operating expenses	547	453	152	4	200		1,356
Operating income (loss)	$ (18)	$ 71	$ 34	$ 66	$ (120)	$	$ 33
Total assets at September 30, 2011	$ 4,465	$ 3,291	$ 820	$ 1,616	$ 3,672[5]	$ (2,150)	$ 11,714

(1) Includes unrealized gains (losses) of $(80) million, $2 million, $4 million and $(12) million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.
(2) Includes unrealized (gains) losses of $(17) million, $(8) million, $(1) million and $(1) million for Eastern PJM, Western PJM/MISO, Energy Marketing and Other Operations, respectively.
(3) Includes $61 million of merger-related costs.
(4) Represents impairment losses for the write off of excess NO_x and SO_2 emissions allowances as a result of the CSAPR. See note 5.
(5) Includes our equity method investment in Sabine Cogen, LP of $21 million.

Operating Segments

	00000000	00000000	00000000	00000000	00000000	00000000	00000000
	Eastern PJM	**Western PJM/MISO**	**California**	**Energy Marketing (in millions)**	**Other Operations**	**Eliminations**	**Total**
Three Months Ended September 30, 2010:							
Operating revenues[1]	$ 653	$	$ 41	$ (7)	$ 88	$	$ 775
Cost of fuel, electricity and other products[2]	182		9	(3)	59		247
Gross margin (excluding depreciation and amortization)	471		32	(4)	29		528
Operating Expenses:							
Operations and maintenance	116		15	2	39[3]		172
Depreciation and amortization	36		8		9		53

Gain on sales of assets, net					(1)		(1)
Total operating expenses	152		23	2	47		224
Operating income (loss)	$ 319	$	$ 9	$ (6)	$ (18)	$	$ 304

(1) Includes unrealized gains (losses) of $156 million, $(10) million and $8 million for Eastern PJM, Energy Marketing and Other Operations, respectively.

(2) Includes unrealized (gains) losses of $(23) million and $10 million for Eastern PJM and Other Operations, respectively.

(3) Includes $8 million of merger-related costs.

Table of Contents

	00000000	00000000	00000000	00000000	00000000	00000000	00000000
	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Nine Months Ended September 30, 2010:							
Operating revenues[1]	$ 1,562	$	$ 112	$ 25	$ 200	$	$ 1,899
Cost of fuel, electricity and other products[2]	587		21	(3)	121		726
Gross margin (excluding depreciation and amortization)	975		91	28	79		1,173
Operating Expenses:							
Operations and maintenance	346		53	7	64[3]		470
Depreciation and amortization	105		23	1	28		157
Gain on sales of assets, net	(3)				(1)		(4)
Total operating expenses	448		76	8	91		623
Operating income (loss)	$ 527	$	$ 15	$ 20	$ (12)	$	$ 550
Total assets at December 31, 2010	$ 4,892	$ 3,763	$ 747	$ 2,767	$ 6,907[4]	$ (3,865)	$ 15,211

(1) Includes unrealized gains (losses) of $289 million, $(13) million and $10 million for Eastern PJM, Energy Marketing and Other Operations, respectively.
(2) Includes unrealized losses of $81 million and $26 million for Eastern PJM and Other Operations, respectively.
(3) Includes $13 million of merger-related costs.
(4) Includes our equity method investment in Sabine Cogen, LP of $21 million.

	September 30, Three Months Ended September 30, 2011	September 30, 2010	September 30, Nine Months Ended September 30, 2011	September 30, 2010
		(in millions)		
Operating income for all segments	$ 47	$ 304	$ 33	$ 550
Interest expense	(86)	(51)	(291)	(150)
Interest income	1		1	
Other, net	1	1	(21)	(1)
Income (loss) before income taxes	$ (37)	$ 254	$ (278)	$ 399

13. 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.

Scrubber Contract Litigation

In January 2011, Stone & Webster, the EPC contractor for the scrubber projects at the Chalk Point, Dickerson and Morgantown generating 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 $143.1 million in liens against the properties. In

March 2011, the court granted these liens. In June 2011, Stone & Webster filed a motion to amend its lien claims at these facilities by an additional $90.5 million. In August 2011, the court granted these additional liens. In September 2011, GenOn Mid-Atlantic paid $68 million to Stone & Webster for achieving substantial completion under the EPC agreements, which

Table of Contents

reduced the outstanding liens amount to $165.6 million. As a result of certain lien restrictions in its lease documentation, GenOn Mid-Atlantic has reserved $165.6 million of cash (which is included in funds on deposit on the unaudited condensed consolidated balance sheet) in respect of such liens. The liens are interlocutory only and will not become final unless and until Stone & Webster is successful in prosecuting its contractual claims. 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. Currently, $1.674 billion continues to represent management s best estimate of the total capital expenditures for compliance with the Maryland Healthy Air Act. However, if the costs incurred were to equal the amount claimed by Stone &Webster, the total capital expenditures would exceed $1.674 billion by approximately 5%.

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. In July 2011, the judge in the United States District Court for the District of Nevada handling four of the five cases granted the defendants motion for summary judgment dismissing all claims against us in those cases. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. The fifth case is pending in the State of Nevada Supreme Court on plaintiff s appeal of the dismissal of all its claims by the Eighth Judicial District Court for Clark County, Nevada. We have agreed to indemnify CenterPoint against certain losses relating to these lawsuits.

Environmental Matters

Conemaugh NPDES Permit. In April 2007, PennEnvironment and the Sierra Club filed a citizens suit against us in the United States District Court for the Western District of Pennsylvania to enforce provisions of the water discharge permit for the Conemaugh generating facility, of which we are the operator and have a 16.45% interest. In March 2011, the court granted partial summary judgment on liability against us. In August 2011, the court entered a consent decree settling the enforcement action brought by PennEnvironment and the Sierra Club in exchange for the Conemaugh owners paying an aggregate amount of $5 million in civil penalties, plaintiffs legal fees and funding to support environmental projects that will benefit the Conemaugh River watershed. We are responsible for 16.45% ($822,500) of this amount.

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.

Montgomery County Carbon Emissions Levy. The Dickerson generating facility is located in Montgomery County, Maryland, and 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 estimated that the CO_2 levy would have imposed $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 was unlawful. In July 2010, the District Court ruled that the CO_2 levy was 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 appealed that ruling to the United States Court of Appeals for the Fourth Circuit. In June 2011, the United States Court of Appeals for the Fourth Circuit overturned the dismissal and remanded the case to the District Court. In July 2011, following the decision of the Court of Appeals, Montgomery County repealed the carbon emissions levy. We have been refunded all amounts previously paid, with interest.

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 regulations regarding new source review. In June 2011, we received an NOV from the EPA alleging that past work at our Niles and Avon Lake generating facilities violated regulations regarding new source review.

In December 2007, the New Jersey Department of Environmental Protection (NJDEP) 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 NJDEP 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.

In addition, the NJDEP 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 New Jersey. In April 2011, the EPA addressed one of the two petitions and proposed to find that the SO_2 emissions from the two coal-fired units at the Portland generating facility significantly contribute to nonattainment and interfere with the maintenance of the one-hour SO_2 NAAQS in New Jersey. The EPA solicited comments 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. In November 2011, the EPA published a final rule that will require us to reduce our maximum allowable SO_2 emissions from these two coal units by about 60% starting in January 2013 and by about 80% starting in January 2015. In 2013 and 2014, we have several compliance options that include using lower sulfur coals (although this may at times reduce how much we are able to generate) or running just one unit at a time. Starting in January 2015, these units will also be subject to more stringent rate limits, which will require either material capital expenditures and higher operating costs or the retirement of these two units.

Potomac River NOV. In August 2011, the Virginia DEQ issued an NOV related to the Potomac River generating facility. The Virginia DEQ asserted that (a) the facility is not equipped with all the appropriate fugitive dust controls, (b) we failed to correctly calculate NO_x emissions rates and (c) NO_x emissions exceeded the permitted limits on six days in June and July 2011. We contest the allegations.

Cheswick Monarch Mine NOV. In 2008, the PADEP issued an NOV related to the Monarch mine located near our Cheswick generating facility. The mine, a former coal mine, has not been mined for many years. We use it for disposal of low-volume wastewater from the Cheswick generating facility and for disposal of leachate collected from ash disposal facilities. The NOV addresses the alleged requirement to maintain a minimum pumping volume from the mine. The PADEP recently indicated it may assess a civil penalty in excess of $100,000. We contest the allegations in the NOV and have not agreed to such penalty. We are currently assessing the need for capital expenditures in connection with water at the mine.

Maryland Fly Ash Facilities. We have three fly ash facilities in Maryland: Faulkner, Westland and Brandywine. We dispose of fly ash from our Morgantown and Chalk Point generating facilities at Brandywine. We dispose of fly ash from our Dickerson generating facility at Westland. We no longer dispose of fly ash at the Faulkner facility. As described below, the MDE has sued us regarding Faulkner and Brandywine and threatened to sue regarding Westland. The MDE also has threatened not to renew the water discharge permits for all three facilities.

Faulkner Litigation. In May 2008, the MDE sued 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

Table of Contents

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, the 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 facility 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.

Brandywine Litigation. 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.

Threatened Westland Litigation. In January 2011, the MDE informed us that it intends to sue us for alleged violations of Maryland s water pollution laws at Westland. To date, MDE has not sued us regarding our ash disposal at Westland.

Permit Renewals. 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 also indicated that it was planning 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.

Stay and Settlement Discussions. In June 2011, the MDE agreed to stay the litigation related to Faulkner and Brandywine while we pursue settlement of allegations related to the three Maryland ash facilities. MDE also agreed not to pursue its tentative denial of our application to renew our water discharge permit at Brandywine and agreed not to act on our renewal applications for Faulkner or Westland while we are discussing settlement. As a condition to obtaining the stay, we agreed in principle to pay a civil penalty of $1.9 million to the MDE if we reach a comprehensive settlement regarding all of the allegations related to the three Maryland ash facilities. Accordingly, we accrued $1.9 million during the three months ended June 30, 2011. We also developed a technical solution, which included installing synthetic caps on portions of each of the ash facilities, that we thought would address the MDE s concerns at the three ash facilities. During the three months ended June 30, 2011, we accrued $28 million for the estimated cost of the technical solution. In October 2011, the MDE informed us that our proposed technical solution was not adequate in the MDE s view. At this time, we cannot reasonably estimate the upper range of our obligations for remediating the sites for the following reasons: (a) we have not finished assessing each site including identifying the full impacts to both ground and surface water and the impacts to the surrounding habitat; (b) we have not finalized with the MDE the standards to which we must remediate; and (c) we have not identified the technologies required, if any, to meet the mandated remediation standards at each site nor the timing of the design and installation of such technologies. There are no assurances that we will be able to settle the three matters for the amounts that we have accrued and the ultimate resolution of these matters could be material to our results of operations, financial position and cash flows.

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 ($34 million and $36 million at September 30, 2011 and December 31, 2010, respectively) associated with these environmental liabilities as part of the asset retirement obligations. These amounts are exclusive of the $28 million accrual for the technical solution for three ash facilities in Maryland discussed above.

Table of Contents

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 September 30, 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

Table of Contents

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.

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 $70 million (including interest and penalties through September 30, 2011 of $27 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.

Table of Contents

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 September 30, 2011, our generating capacity was 56% in PJM, 22% in CAISO, 11% in NYISO and ISO-NE, 10% in the Southeast and 1% 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. We expect to achieve approximately $160 million in annual cost savings, starting in January 2012, through reduced overhead and support costs.

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. During the three months ended September 30, 2011, we recorded interim revisions to the provisional allocation of the purchase price at December 3, 2010 and accordingly revised amounts in our consolidated balance sheet at December 31, 2010 and our consolidated statements of operations for 2010 and the three and six months ended June 30, 2011. See note 2 to our interim financial statements for further discussion of the Merger and these revisions.

Table of Contents

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 October 31, 2011, our aggregate hedge levels increased in part based on expected reduced generation considering the effects of the CSAPR and were as follows:

	September 30, 2012	September 30, 2013	September 30, 2014	September 30, 2015	September 30, 2016
Power	72%	40%	21%	12%	9%
Fuel	58%	40%	14%	9%	8%

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 us, 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. Furthermore, the CFTC and federal banking regulators proposed capital requirements for SD/MSPs recommend significant and cash-dependent capital requirements for SD/MSPs. The cost of complying with these requirements may be passed through to and imposed on commercial end users indirectly and increase the cost of our hedging activities.

The CFTC has also issued its proposed definition of swap. In further defining the term, the CFTC has left some ambiguity as to whether what are commonly understood as commodity options (which can settle physically) are to be generally considered swaps. With regard to electric power ISO/RTO products, including Financial Transmission Rights (FTRs), the CFTC has said only that it will consider granting exemptions to transactions where an instrument regulated by FERC is involved and such an exclusion would be in the public interest. If applied to our hedging activity, such regulations could considerably increase the transaction costs with respect to commodity options and FTRs.

Table of Contents

Moreover, the CFTC issued a proposal establishing recordkeeping and reporting requirements for swaps entered into before July 21, 2010, whose terms had not expired as of that date, and data relating to swaps entered into on or after July 21, 2010 and prior to the compliance date specified in the CFTC s final swap data reporting rules. Additionally, in July 2011, the CFTC adopted final large trader reporting rules for physical commodity swaps and swaptions. Although we will have increased reporting and recordkeeping requirements under both proposals, we do not expect the proposed requirements to have a material effect on our hedging activities.

In terms of the timing for the release and implementation of the rules established by Dodd-Frank, in July 2011, the CFTC issued an order clarifying the effective date of the provisions in the swap regulatory regime as the CFTC continues to implement rules. The order provides temporary relief from certain provisions that would otherwise apply to swaps or swap dealers and that would have become effective as of July 16, 2011, until the CFTC completes the rulemakings specified in the order. This order is temporary, and it will expire upon the earlier of the effective date of final rules or December 31, 2011. In an open meeting in September 2011, Chairman Gensler indicated that the CFTC will not meet the extended deadline of December 31, 2011. The CFTC subsequently published an outline indicating that they may consider final rules in 2011 including entity and product definitions, position limits, the end-user exemption, and recording and reporting rules. The outline also indicated that the CFTC may consider final rules during the first quarter of 2012 including capital and margin requirements, client clearing documentation and risk management and internal business conduct rules. The CFTC indicated that the outline provided was subject to change and that the dates and order in which the CFTC finalizes its Dodd-Frank rulemaking could differ substantially from those provided in the outline. In the meantime, the CFTC has proposed an amendment extending the exemptive relief to July 16, 2012, or until a date the CFTC may otherwise determine with respect to a particular requirement under the Commodity Exchange Act.

In addition, in September 2011, the CFTC proposed swaps compliance and implementation schedules for mandatory clearing and trading, trading documentation and uncleared margin. The CFTC s notice of proposed rulemaking would give the CFTC discretion to phase in implementation of any clearing mandate for 90, 180 or 270 days, depending on the types of entities that are party to the relevant swap. The trigger for the implementation phase-in period would be the issuance of a clearing mandate by the CFTC. The CFTC also issued a further notice of proposed rulemaking with respect to margin and documentation requirements that would establish implementation schedules of 90, 180 or 270 days, depending on the types of entities involved. The CFTC has proposed, but not yet adopted, regulations implementing both of these provisions. As the entity and product definitions have not been finalized, we cannot fully assess the impact of these proposals.

Capital Expenditures and Capital Resources

During the nine months ended September 30, 2011, we invested $319 million for capital expenditures, excluding capitalized interest paid. Capital expenditures for the period primarily relate to the construction of the Marsh Landing generating facility, maintenance capital expenditures and include the $68 million payment to Stone & Webster for substantial completion of the scrubber projects. At September 30, 2011, we have invested $1.59 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 projects. 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 13 to our interim financial statements for further discussion of the scrubber contract litigation.

Table of Contents

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, 2012 and 2013:

	September 30, October 1, 2011 through December 31, 2011	September 30, 2012	September 30, 2013
		(in millions)	
Maryland Healthy Air Act	$ 84	$	$
Other environmental	14	57	76
Maintenance	42	105	136
Marsh Landing generating facility	83	329	63
Other construction	21	8	
Other	8	17	10
Total	$ 252	$ 516	$ 285

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 total capital expenditures for the Marsh Landing generating facility pursuant to the GenOn Marsh Landing project financing facility entered into 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

We decide to invest capital for environmental controls based on relatively certain regulations, an evaluation of various options for regulatory compliance, including different technologies and fuel modification, and the expected economic returns on the capital. Whether we elect to install additional controls as a result of existing or pending regulations remains uncertain and depends on, among other things, the content and timing of the full slate of regulations, the expected effect of regulations on wholesale power prices and allowance prices, as well as the cost of controls, profitability of our generating facilities, market conditions at the time and the likelihood of CO_2 regulation.

The costs associated with more stringent environmental air and water quality requirements, including state-specific or regional regulatory initiatives, may result in coal-fired generating facilities, including some of ours, being retired. Implementation of a program putting a price on emissions of CO_2 in addition to other emissions control requirements could increase the likelihood of retirements of coal-fired generating facilities. See discussion under HAPs Regulations below.

We expect any such industry retirements to contribute to improving supply and demand fundamentals for the remaining generating facilities. Any resulting increased demand for natural gas could increase the spread between natural gas and coal prices, which would also benefit the remaining coal-fired generating facilities. Consequently, we expect industry retirements to result in higher market power prices, which we think will result in our investing approximately $565 million to $700 million over the next nine years for SCRs and other environmental controls to meet certain air and water quality requirements, which we expect to fund from existing sources of liquidity. Current market prices do not support this level of investment. Under current and forecasted market conditions, we do not expect installations of scrubbers to be economic at most of our unscrubbed coal-fired facilities. If market power prices rise even higher than our current expectations, we might invest more than $700 million for environmental controls.

Given the uncertainty related to these environmental matters and those discussed or referred to below, we cannot predict their actual outcome or ultimate effect on our business, and such matters could result in a material adverse effect on our results of operations, financial position and cash flows. See also our discussion under the caption Environmental Matters in note 13 to our interim financial statements, including the discussion of petitions filed by the New Jersey Department of Environmental Protection related to our Portland generating facility and the discussion regarding our Brandywine, Faulkner and Westland ash facilities.

Cross-State Air Pollution Rule. In 2005, the EPA promulgated the CAIR, which established SO_2 and NO_x cap-and-trade programs applicable directly to states and indirectly to generating facilities in the eastern United States. The NO_x cap-and-trade program has two components: an annual program and an ozone-season program. The CAIR SO_2 cap-and-trade program builds off the existing acid rain cap-and-trade program but requires generating facilities to surrender twice as many allowances to cover emissions from 2010 through 2014 and approximately three times as many allowances starting in 2015. Florida, Illinois, Maryland, Mississippi, New Jersey, New York, Ohio, Pennsylvania and Virginia are subject to the CAIR s SO_2 trading program and both its NO_x trading programs. Massachusetts is subject only to the CAIR s ozone-season NO_x trading program. These cap-and-trade programs were to be implemented in two phases, with the first phase going into effect in 2009 for NO_x and 2010 for SO_2 and more stringent caps going into effect in 2015. In July 2008, the D.C. Circuit in *State of North Carolina v. Environmental Protection Agency* issued an opinion that would have vacated the CAIR. Various parties filed requests for rehearing with the D.C. Circuit and in December 2008, the D.C. Circuit issued a second opinion in which it granted rehearing only to the extent that it remanded the case to the EPA without vacating the CAIR. Accordingly, the CAIR will remain effective until it is replaced by a rule consistent with the D.C. Circuit s opinions, which as described below will take place in January 2012.

In August 2011, the EPA finalized the regulations to replace the CAIR with the CSAPR starting in 2012. The CSAPR addresses interstate transport of emissions of NO_x and SO_2. In September 2011, we (and others) asked the United States Court of Appeals for the D.C. Circuit to stay and vacate the CSAPR because, among other reasons, the rule circumvents the state implementation plan process expressly provided for in the Clean Air Act, affords affected parties no time to install compliance equipment before the compliance period starts and includes numerous material changes from the proposed rule, which deprived parties of an opportunity to provide comments.

The CSAPR establishes limitations on NO_x and/or SO_2 emissions from electric generating units that are (i) greater than 25 megawatts and (ii) located in 27 states (in the eastern half of the United States) that the EPA determined contribute significantly to nonattainment in other states, or to interfere with maintenance in other states, of one or more of three NAAQS: (a) the annual NAAQS for fine particulate matter ($PM_{2.5}$) promulgated in 1997; (b) the 24-hour NAAQS for $PM_{2.5}$ promulgated in 2006 and (c) the ozone NAAQS promulgated in 1997. The CSAPR creates emission budgets for each of the covered states and allocates emissions allowances (denominated in tons of emissions) to each of the 27 states regulated under the CSAPR. Under the EPA federal implementation plan, for 2012, we were allocated 31,901, 14,724, and 78,129 allowances under the CSAPR for annual NO_x, ozone-season NO_x, and SO_2, respectively. The federal implementation plan has also outlined EPA-determined allocations in the same amounts for 2013, although the CSAPR contemplates that states after 2012 may allocate allowances in a different manner than allocated initially under the CSAPR. In October 2011, the EPA proposed revisions to the final CSAPR that, if finalized, would provide us with a small allowance increase in each compliance year. As a result, our expected CSAPR allowances would be 31,944, 14,768 and 78,193 in 2012, and 31,979, 14,785 and 78,331 in 2013, for annual NO_x, ozone-season NO_x and SO_2, respectively. The CSAPR limits each electric generating unit s NO_x and SO_2 emissions to amounts covered by the number of allowances held by that source in allowance accounts under the program (which may be purchased or otherwise acquired from other sources, subject to certain limitations in the rule).

The NO_x allowances from the CAIR program will not be used in the CSAPR program and accordingly will have no value after 2011. The SO_2 allowances used for compliance in the CAIR program are the acid rain program allowances, which will have negligible value after 2011. As a result of the CSAPR, we recorded impairment losses of $133 million for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011. See note 5 to our interim financial statements for further discussion of the impairment losses.

We expect that the CSAPR will result in reduced generation volumes from uncontrolled coal-fired plants, increased generation from gas-fired plants, increased market power prices and increased emissions costs offset by allocated allowances. The effect of the CSAPR on our adjusted EBITDA is dependent on the price of the emissions allowances, liquidity in the emissions allowances markets and whether we choose to monetize the allowances. Based on current market conditions, the CSAPR is expected to have a negative effect on our adjusted EBITDA, which includes carrying excess CSAPR emissions allowances to future periods to optimize their value. Our long term results are dependent on market conditions and pending environmental regulations, including how states allocate the CSAPR allowances and finalization of HAPs-MACT. As currently proposed, HAPs-MACT is expected to mitigate the CSAPR effect starting in the second half of the decade. In addition to evaluating the effects of the CSAPR on our business and our ongoing evaluation of the wholesale energy market, our future decisions to mothball, retire or dispose of facilities could result in impairment charges related to our fixed assets.

Table of Contents

The EPA also has stated that it may issue a subsequent, more stringent rule if it concludes that recent or planned revisions to the particulate matter and ozone NAAQS make necessary more stringent limits on SO_2 and NO_x emissions from electric generating facilities.

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 for compliance beginning in 2015. If finalized, these MACT standards (i) will require us as a condition of continuing to operate to install and operate additional emissions control equipment at some of our facilities, the cost of which will be material and (ii) will result in the shutdown or retirement of some coal-fired facilities, including some of ours, for which current and forecasted market conditions do not justify the required capital expenditures. We expect that higher earnings from price increases resulting from industry retirements will more than offset reduced earnings from our unit retirements.

RGGI. The RGGI is a multi-state initiative in the Eastern PJM and Northeast outlining a cap-and-trade program to reduce CO_2 emissions from electric generating units with capacity of 25 MW or greater. The RGGI program calls for signatory states, which include Maryland, Massachusetts, New Jersey and New York, to stabilize CO_2 emissions to an established baseline from 2009 through 2014, followed by a 2.5% reduction each year from 2015 through 2018. In June 2011, New Jersey informed RGGI that it is withdrawing from the program effective December 31, 2011. The withdrawal by New Jersey is not expected to have a material effect on our operations.

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 the CARB remedies various procedural flaws related to the CARB s environmental review of the Scoping Plan under the California Environmental Quality Act. The CARB appealed the decision. A state appellate court stayed the injunction, allowing the CARB to continue to develop the final cap-and-trade regulation. However, the CARB indicated in June 2011 that while it still intends to initiate the cap-and-trade program in 2012, compliance requirements imposed by the rule will be delayed one year until 2013. In October 2011, the CARB adopted these final cap-and-trade regulations with an initial compliance period of 2013-2014 for electric utilities and large industrial facilities. 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. However, in accordance with our tolling agreements for the Northern California generating facilities, we would pass any applicable costs through to the counterparties. We have hedged some of the output of our facilities with structures other than tolling agreements. With these hedges we retain some limited exposure to costs associated with the cap-and-trade regulation.

Water Regulations. 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 final rule may differ from the proposal as a result of the public comment 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.

Shawville NPDES Permit Appeal. In August 2010, the PADEP issued a renewed NPDES permit effective September 2010 that contains discharge limits for the leased Shawville generating facility that require installation of cooling towers or reduction in plant operation by September 1, 2013. The Pennsylvania Fish & Boat Commission and we appealed the permit to the Pennsylvania Environmental Hearing Board. We have recently entered into an agreement that when approved by the Pennsylvania Environmental Hearing Board would allow the permit to be amended to delay this requirement until July 31, 2015. While we will continue to evaluate the economics of installing cooling towers and other expected environmental capital expenditures for the Shawville generating facility, such capital expenditures are not justified under current and forecasted market conditions. Under the lease agreement for Shawville, our obligations generally are to pay the required rent and to maintain the leased assets in accordance with the lease documentation, including in compliance with prudent competitive electric generating industry practice and applicable laws. We are evaluating our options under the lease, including termination of the lease for economic obsolescence or placing the facility in long-term protective layup pending the determination to return the facility to operation or the termination of the lease upon early termination or expiration. We do not think that the lease documentation mandates that we operate the facility continuously and, so long as we are not operating it, we do not think that the installation of cooling towers, emissions controls and other expenditures would be required. In the event of a long-term protective layup of the Shawville facility, we would continue to pay the required rent and to maintain the facility as required by the lease. In the event of an early termination, we would seek a termination for obsolescence under the lease agreement and could be required to make a termination payment equal to the difference between the termination value and the proceeds received in connection with the sale of the facility to a third-party, together with such other amounts, if any, required under the lease. At September 30, 2011, the termination value of the lease was $216 million.

Seward NPDES Permit Appeal. The PADEP issued the Seward generating facility a renewed NPDES permit in July 2010. In September 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. In May 2011, the appeal was dismissed because plaintiffs voluntarily dismissed their challenge.

Potrero Shutdown

On February 28, 2011, the Potrero generating facility was shut down. See note 19 to our consolidated financial statements in our 2010 Annual Report on Form 10-K for further discussion.

Table of Contents

Potomac River Retirement

In August 2011, we entered into an agreement with the City of Alexandria, Virginia to remove permanently from service our Potomac River generating facility on October 1, 2012, subject to the receipt of all necessary consents and approvals. PJM has determined that the retirement of the facility will not affect reliability. We must now receive consent from PEPCO. If the PEPCO consent has not been received by July 3, 2012, the Potomac River generating facility will be retired within 90 days after the receipt thereof. Upon retirement of the Potomac River generating facility, all funds in a related account shall be distributed to us, provided that, if the retirement of the facility is after January 1, 2014, $750,000 of such funds shall be paid to the City of Alexandria. Currently, approximately $32 million is held in the escrow account. We do not expect any material diminution in the amount on deposit in the escrow account between now and disbursement of the funds to us. We do not expect the closing of the Potomac River generating facility to have a material effect on our business, results of operations, financial position or cash flows. See note 5 to our interim financial statements for further discussion of the retirement of the Potomac River generating facility and the impairment losses recognized in 2010.

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 are designated as hedges (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/loss from continuing 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 and nine months ended September 30, 2010. As mentioned above, management generally evaluates our operating results excluding the effect of unrealized gains and losses. Adjusted income/loss from continuing operations and adjusted EBITDA also exclude, as applicable: (a) merger-related costs, (b) net lower of cost or market adjustments to our commodity inventories, (c) impairment losses, (d) gain/loss on early extinguishment of debt, (e) Western states litigation and similar settlements, (f) large scale remediation and settlement costs, (g) major litigation costs, net of recoveries, (h) postretirement benefits curtailment gain, (i) reversal of the Montgomery County carbon levy assessment for the prior year, and (j) 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.

Table of Contents

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 incentive compensation 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.

The foregoing non-GAAP financial measures may not be comparable to similarly titled non-GAAP financial measures used by other companies.

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010

Consolidated Financial Performance

We reported a net loss of $38 million and net income of $254 million during the three months ended September 30, 2011 and 2010, respectively. The change in net income/loss is detailed as follows:

	September 30, Three Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Realized gross margin	$ 516	$ 361	$ 155
Unrealized gross margin	38	167	(129)
Total gross margin (excluding depreciation and amortization)	554	528	26
Operating expenses:			
Operations and maintenance	286	172	114
Depreciation and amortization	94	53	41
Impairment losses	133		133
Gain on sales of assets, net	(6)	(1)	(5)
Total operating expenses	507	224	283
Operating income	47	304	(257)
Other income (expense), net:			
Interest expense, net	(85)	(51)	34
Other, net	1	1	
Total other expense, net	(84)	(50)	34
Income (loss) before income taxes	(37)	254	(291)
Provision for income taxes	1		1
Net income (loss)	$ (38)	$ 254	$ (292)

Realized Gross Margin. Our realized gross margin increase of $155 million was principally a result of the following:

an increase of $139 million in contracted and capacity primarily as a result of $185 million from the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by a decrease of $46 million primarily resulting from lower capacity prices in our Eastern PJM and Other Operations segments and the shutdown of the Potrero generating facility in our California segment; and

an increase of $14 million in energy primarily as a result of $114 million from the addition of the 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 spark spreads.

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

- unrealized gains of $38 million during the three months ended September 30, 2011, which included a $71 million net increase in the value of hedge and proprietary trading contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by $33 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period; and

- unrealized gains of $167 million during the three months ended September 30, 2010, which included a $243 million net increase in the value of hedge and proprietary trading contracts for future periods primarily related to decreases in forward power and natural gas prices and increases in forward coal prices, offset by $76 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 $283 million was principally a result of the following:

- an increase of $133 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances included in intangible assets ($75 million) and the write-off of excess NO_x and SO_2 emissions allowances previously included in property, plant and equipment ($58 million) during the three months ended September 30, 2011 as a result of the CSAPR;

- an increase of $114 million in operations and maintenance expense primarily as a result of the addition of the RRI Energy generating facilities, corporate costs as a result of the Merger and an increase of $16 million in merger-related costs primarily for severance; and

- an increase of $41 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 reduction in the carrying value of the Dickerson and Potomac River generating facilities as a result of impairment losses in the fourth quarter of 2010, and the shutdown of the Potrero generating facility.

Interest Expense, Net. Our interest expense, net increase of $34 million was principally a result of the following:

- a $75 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

- a $33 million decrease related to lower interest expense as a result of (a) repayment of the GenOn North America senior secured credit facilities and senior notes in December 2010 and January 2011, respectively, and (b) repayment of the GenOn Americas Generation senior unsecured notes in May 2011.

Adjusted Income/Loss from Continuing Operations and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted income/loss from continuing operations and adjusted EBITDA to net income/loss on historical and pro forma bases. See the discussion above 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 September 30, 2011 to pro forma information for the three months ended September 30, 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;

Table of Contents

- 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 September 30,		
	September 30, 2011	September 30, Pro Forma 2010	September 30, 2010
		(in millions)	
Net Income (Loss)	$ (38)	$ 339	$ 254
Impairment losses	133	113[1]	
Merger-related costs	24		8
Major litigation costs, net of recoveries	5		
Lower of cost or market inventory adjustments, net	(1)	(8)	(7)
Unrealized gains	(38)	(218)	(167)
Other	(9)	(2)	(2)
Adjusted income from continuing operations	76	224	86
Interest expense, net	85	95	51
Provision for income taxes	1		
Depreciation and amortization	94	96	53
Adjusted EBITDA	$ 256	$ 415	$ 190

(1) During the three months ended September 30, 2010, RRI Energy recognized impairment losses of $113 million for its Titus and New Castle generating facilities.

Adjusted EBITDA was $256 million for the three months ended September 30, 2011 compared to $415 million on a pro forma basis for the same period of 2010. The decline was primarily related to reduced generation volumes in Eastern PJM and Western PJM/MISO, a decrease in our fuel oil management activities and lower contracted and capacity revenues from Eastern PJM and Western PJM/MISO. The decline was partially offset by lower adjusted operating and other expenses, primarily related to merger cost savings.

Adjusted income from continuing operations was $76 million for the three months ended September 30, 2011 compared to $224 million on a pro forma basis for the same period of 2010. The decline was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in interest expense, net.

Our net loss was $38 million for the three months ended September 30, 2011 compared to net income of $339 million on a pro forma basis for the same period of 2010. The decline was primarily a result of lower unrealized gross margin, $133 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR, an increase in merger-related costs and the same items that affected adjusted EBITDA. The decline was partially offset by impairment losses in 2010 related to the Titus and New Castle generating facilities that were not repeated in 2011.

Table of Contents

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:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Three Months Ended September 30, 2011						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Energy	$ 64	$ 107	$ 6	$ 1	$ 7	$	$ 185
Contracted and capacity	65	77	109		23		274
Realized value of hedges	50	7	1		(1)		57
Total realized gross margin	179	191	116	1	29		516
Unrealized gross margin	(12)	36	1	16	(3)		38
Total gross margin[1]	$ 167	$ 227	$ 117	$ 17	$ 26	$	$ 554

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Three Months Ended September 30, 2010						
	Eastern PJM	Western PJM/MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Energy	$ 151	$	$	$ 6	$ 14	$	$ 171

Contracted and capacity	83		32		20		135
Realized value of hedges	58				(3)		55
Total realized gross margin	292		32	6	31		361
Unrealized gross margin	179			(10)	(2)		167
Total gross margin[1]	$ 471	$	$ 32	$ (4)	$ 29	$	$ 528

(1) Gross margin excludes depreciation and amortization.

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

48

Table of Contents

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts (which we had at Potrero 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 92% during the three months ended September 30, 2011. The following table summarizes power generation volumes by segment:

	September 30, Three Months Ended 2011	**September 30, September 30, 2010 (in gigawatt hours)**	**September 30, Increase/ (Decrease)**	**September 30, Increase/ (Decrease)**
Eastern PJM:				
Baseload	3,024	4,060	(1,036)	(26)%
Intermediate	478	733	(255)	(35)%
Peaking	62	121	(59)	(49)%
Total Eastern PJM	3,564	4,914	(1,350)	(27)%
Western PJM/MISO:				
Baseload	5,093		5,093	N/A
Intermediate	1,214		1,214	N/A
Peaking	52		52	N/A
Total Western PJM/MISO	6,359		6,359	N/A
California:				
Intermediate	204	255	(51)	(20)%
Peaking		(1)	1	100%
Total California	204	254	(50)	(20)%
Other Operations:				
Baseload	672	400	272	68%
Intermediate	162	324	(162)	(50)%
Peaking	214	5	209	N/A
Total Other Operations	1,048	729	319	44%
Total	11,175	5,897	5,278	90%

The total increase in power generation volumes during the three months ended September 30, 2011, as compared to the same period in 2010, was primarily the result of the following:

Eastern PJM. The decrease in our baseload and intermediate generation volumes was primarily as a result of contracting dark spreads and spark spreads.

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

California. The decrease in our intermediate generation volumes was primarily related to the shutdown of the Potrero generating facility, offset in part by the addition of the RRI Energy generating facilities as a result of the Merger.

Table of Contents

Other Operations. The increase in our baseload and peaking generation volumes was primarily related to the addition of the RRI Energy generating facilities as a result of the Merger, offset in part by a decrease in our baseload and intermediate generation for our facilities located in the Northeast as a result of a reduction in our available capacity at our Bowline generating facility, an outage at one of our generating facilities and contracting spark spreads in New England.

Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,336 MW at September 30, 2011 and four generating facilities with total net generating capacity of 5,204 MW at September 30, 2010.

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

	September 30, Three Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 64	$ 151	$ (87)
Contracted and capacity	65	83	(18)
Realized value of hedges	50	58	(8)
Total realized gross margin	179	292	(113)
Unrealized gross margin	(12)	179	(191)
Total gross margin (excluding depreciation and amortization)	167	471	(304)
Operating Expenses:			
Operations and maintenance	99	116	(17)
Depreciation and amortization	34	36	(2)
Impairment losses	95		95
Total operating expenses, net	228	152	76
Operating income (loss)	$ (61)	$ 319	$ (380)

Gross Margin

The decrease of $113 million in realized gross margin was principally a result of the following:

a decrease of $87 million in energy, primarily as a result of a decrease in generation volumes as a result of contracting dark spreads and spark spreads;

a decrease of $18 million in contracted and capacity primarily as a result of a $24 million decrease from lower capacity prices and a $4 million decrease from ancillary services, offset in part by $11 million from the addition of the RRI Energy generating facilities as a result of the Merger; and

a decrease of $8 million in realized value of hedges, primarily as a result of a $10 million decrease in power hedges resulting from prices and volumes hedged, partially offset by a $2 million increase in our coal hedges resulting from prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $12 million during the three months ended September 30, 2011, which included $41 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, offset by a $29 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices; and

Table of Contents

unrealized gains of $179 million during the three months ended September 30, 2010, which included a $228 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, offset by $49 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $76 million in operating expenses was principally a result of the following:

- an increase of $95 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR; partially offset by

- a decrease of $17 million in operations and maintenance expense primarily as a result of (a) a $6 million decrease resulting from changes in asset retirement obligation assumptions, (b) a change in the allocation methodology for overhead costs as a result of the Merger, (c) a $4 million decrease as a result of the repeal of the Montgomery County CO_2 levy and (d) other cost reductions. These decreases were partially offset by $5 million of major litigation costs, net of recoveries.

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 September 30, 2011.

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

	September 30, Three Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 107	$	$ 107
Contracted and capacity	77		77
Realized value of hedges	7		7
Total realized gross margin	191		191
Unrealized gross margin	36		36
Total gross margin (excluding depreciation and amortization)	227		227
Operating Expenses:			
Operations and maintenance	108		108
Depreciation and amortization	27		27
Impairment losses	4		4
Total operating expenses, net	139		139
Operating income (loss)	$ 88	$	$ 88

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 September 30, 2011 and three generating facilities with total net generating capacity of 2,347 MW at September 30, 2010. Our California segment also includes business development and construction activities for new generation in

California, including GenOn Marsh Landing.

Table of Contents

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

	September 30, Three Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 6	$	$ 6
Contracted and capacity	109	32	77
Realized value of hedges	1		1
Total realized gross margin	116	32	84
Unrealized gross margin	1		1
Total gross margin (excluding depreciation and amortization)	117	32	85
Operating Expenses:			
Operations and maintenance	33	15	18
Depreciation and amortization	11	8	3
Impairment losses	14		14
Gain on sales of assets, net	(5)		(5)
Total operating expenses, net	53	23	30
Operating income (loss)	$ 64	$ 9	$ 55

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. Our Potrero units were subject to RMR arrangements through February 28, 2011, the date of the shutdown. In addition, we have some units in southern California that we operate under tolling agreements with other customers. Our gross margin generally is not affected by changes in power generation volumes from facilities under such arrangements.

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

The increase of $84 million in realized gross margin was primarily a result of the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility.

Operating Expenses

The increase of $30 million in operating expenses was principally a result of the following:

- an increase of $18 million in operations and maintenance expense primarily related to the addition of the RRI Energy generating facilities as a result of the Merger;

- an increase of $14 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR; and an increase of $3 million in depreciation and amortization expense related to the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility, partially offset by

an increase of $5 million in gain on sales of assets as a result of the sale of equipment from our Potrero generating facility.

52

Table of Contents

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:

	September 30, Three Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 1	$ 6	$ (5)
Total realized gross margin	1	6	(5)
Unrealized gross margin	16	(10)	26
Total gross margin (excluding depreciation and amortization)	17	(4)	21
Operating Expenses:			
Operations and maintenance		2	(2)
Depreciation and amortization	1		1
Total operating expenses, net	1	2	(1)
Operating income (loss)	$ 16	$ (6)	$ 22

Gross Margin

The decrease of $5 million in realized gross margin was primarily a result of a decrease in fuel oil management activities, offset in part by an increase in proprietary trading.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $16 million during the three months ended September 30, 2011, which included a $12 million net increase in the value of contracts for future periods and $4 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period; and

- unrealized losses of $10 million during the three months ended September 30, 2010, which included $25 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 contracts for future periods.

Other Operations

Our Other Operations segment consists of nine generating facilities with total net generating capacity of 5,055 MW at September 30, 2011 and four generating facilities with total net generating capacity of 2,535 MW at September 30, 2010. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

Table of Contents

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

	September 30, Three Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 7	$ 14	$ (7)
Contracted and capacity	23	20	3
Realized value of hedges	(1)	(3)	2
Total realized gross margin	29	31	(2)
Unrealized gross margin	(3)	(2)	(1)
Total gross margin (excluding depreciation and amortization)	26	29	(3)
Operating Expenses:			
Operations and maintenance	46	39	7
Depreciation and amortization	21	9	12
Impairment losses	20		20
Gain on sales of assets, net	(1)	(1)	
Total operating expenses, net	86	47	39
Operating income (loss)	$ (60)	$ (18)	$ (42)

Operating Expenses

The increase of $39 million in operating expenses was principally the result of the following:

- an increase of $20 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR;
- an increase of $12 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; and
- an increase of $7 million in operations and maintenance expense primarily related to an increase of $16 million in merger-related costs and the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by a change in the allocation methodology for overhead costs as a result of the Merger and other cost reductions.

Table of Contents

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Consolidated Financial Performance

We reported a net loss of $282 million and net income of $398 million during the nine months ended September 30, 2011 and 2010, respectively. The change in net income/loss is detailed as follows:

	September 30, Nine Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Realized gross margin	$ 1,448	$ 994	$ 454
Unrealized gross margin	(59)	179	(238)
Total gross margin (excluding depreciation and amortization)	1,389	1,173	216
Operating expenses:			
Operations and maintenance	963	470	493
Depreciation and amortization	265	157	108
Impairment losses	133		133
Gain on sales of assets, net	(5)	(4)	(1)
Total operating expenses	1,356	623	733
Operating income	33	550	(517)
Other income (expense), net:			
Interest expense, net	(290)	(150)	140
Other, net	(21)	(1)	20
Total other expense, net	(311)	(151)	160
Income (loss) before income taxes	(278)	399	(677)
Provision for income taxes	4	1	3
Net income (loss)	$ (282)	$ 398	$ (680)

Realized Gross Margin. Our realized gross margin increase of $454 million was principally a result of the following:

- an increase of $314 million in contracted and capacity primarily as a result of $414 million from the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by a decrease of $100 million primarily resulting from lower capacity prices in our Eastern PJM and Other Operations segments and the shutdown of the Potrero generating facility in our California segment;

- an increase of $140 million in energy primarily as a result of $269 million from the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by a decrease in generation volumes in Eastern PJM primarily as a result of contracting dark spreads and spark spreads; and realized value of hedges remained unchanged primarily as a result of an increase in coal hedges primarily as a result of prices and a $23 million increase from the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by a decrease in power hedges as a result of prices.

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

unrealized losses of $59 million during the nine months ended September 30, 2011, which included $160 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, offset by a $101 million net increase in the value of hedge and proprietary trading 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 $179 million during the nine months ended September 30, 2010, which included a $471 million net increase in the value of hedge and proprietary trading contracts for future periods, primarily related to decreases in forward power and natural gas prices offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value was further offset by $292 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 $733 million was principally a result of the following:

- an increase of $493 million in operations and maintenance expense primarily as a result of (a) the addition of the RRI Energy generating facilities and corporate costs as a result of the Merger, (b) an increase of $48 million in merger-related costs primarily for severance, (c) a $37 million curtailment gain recorded in 2010 resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM employees, (d) a $30 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty) and (e) $12 million of major litigation costs, net of recoveries. The increase in operations and maintenance expense was partially offset by a decrease of $14 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to a refund received in the third quarter of 2011 of CO_2 levies paid in 2010;

- an increase of $133 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances included in intangible assets ($75 million) and the write-off of excess NO_x and SO_2 emissions allowances previously included in property, plant and equipment ($58 million) during the three months ended September 30, 2011 as a result of the CSAPR; and

- an increase of $108 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 reduction in the carrying value of the Dickerson and Potomac River generating facilities as a result of impairment losses in the fourth quarter of 2010, and the shutdown of the Potrero generating facility.

Interest Expense, Net. Our interest expense, net increase of $140 million was principally a result of the following:

- a $228 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

- an $80 million decrease related to lower interest expense as a result of (a) repayment of the GenOn North America senior secured credit facilities and senior notes in December 2010 and January 2011, respectively, and (b) repayment of GenOn Americas Generation senior unsecured notes in May 2011.

Other, Net. Our other, net change of $20 million was principally a result of the following:

- $23 million of other expense relating to the loss on early 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.

Table of Contents

Adjusted Income/Loss from Continuing Operations and Adjusted EBITDA. The following table reconciles the non-GAAP consolidated performance measures adjusted income/loss from continuing operations and adjusted EBITDA to net income/loss on historical and pro forma bases. See the discussion above 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 nine months ended September 30, 2011 to pro forma information for the nine months ended September 30, 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.

Table of Contents

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.

	Nine Months Ended September 30, 2011 [1]	Nine Months Ended September 30, Pro Forma 2010 [1]	Nine Months Ended September 30, 2010
	(in millions)		
Net Income (Loss)	$ (282)	$ 163	$ 398
Impairment losses	133	361[2]	
Merger-related costs	61		13
Unrealized (gains) losses	59	(291)	(179)
Large scale remediation and settlement costs	30		
Loss on early extinguishment of debt	23		
Major litigation costs, net of recoveries	12		
Postretirement benefits curtailment gain		(37)	(37)
Western states litigation and similar settlements		17[2]	
Reversal of Montgomery County carbon levy assessment for prior year	(8)		
Lower of cost or market inventory adjustments, net	(13)	(19)	(1)
Other	(9)	(5)	(1)
Adjusted income from continuing operations	6	189	193
Interest expense, net	290	290	150
Provision for income taxes	4	1	1
Depreciation and amortization	265	288	157
Adjusted EBITDA	$ 565	$ 768	$ 501

(1) Amounts have been retroactively amended for the interim revisions to the provisional allocation of the purchase price as further discussed in note 2 to our interim financial statements.

(2) During the nine months ended September 30, 2010, RRI Energy recognized (a) impairment losses of $361 million for its Elrama, Niles, Titus and New Castle generating facilities and (b) $17 million to settle the Western states and other litigation.

Adjusted EBITDA was $565 million for the nine months ended September 30, 2011 compared to $768 million on a pro forma basis for the same period of 2010. The decline was primarily related to a reduction in energy gross margin as a result of reduced generation volumes, primarily in Eastern PJM, and lower contracted and capacity revenues, primarily from Eastern PJM. The decline was partially offset by lower adjusted operating and other expenses, primarily related to merger cost savings and reduced planned outages and projects.

Adjusted income from continuing operations was $6 million for the nine months ended September 30, 2011 compared to $189 million on a pro forma basis for the same period of 2010. The decline was primarily related to the same items that affected adjusted EBITDA, partially offset by a reduction in depreciation and amortization expense.

Our net loss was $282 million for the nine months ended September 30, 2011 compared to net income of $163 million on a pro forma basis for the same period of 2010. The decline was primarily a result of lower unrealized gross margin, $133 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR, an increase in merger-related costs, $30 million of large scale remediation and settlement costs in 2011 and the same items that affected adjusted EBITDA. The decline was partially offset by impairment losses in 2010 related to the Elrama, Niles, Titus and New Castle generating facilities that were not repeated in 2011.

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.

Table of Contents

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:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Nine Months Ended September 30, 2011						
	Eastern PJM	Western PJM/ MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Energy	$ 175	$ 249	$ 10	$ 65	$ 18	$	$ 517
Contracted and capacity	239	246	173		71		729
Realized value of hedges	178	19	3		2		202
Total realized gross margin	592	514	186	65	91		1,448
Unrealized gross margin	(63)	10		5	(11)		(59)
Total gross margin(1)	$ 529	$ 524	$ 186	$ 70	$ 80	$	$ 1,389

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Nine Months Ended September 30, 2010						
	Eastern PJM	Western PJM/ MISO	California	Energy Marketing (in millions)	Other Operations	Eliminations	Total
Energy	$ 321	$	$	$ 41	$ 15	$	$ 377
Contracted and capacity	257		91		67		415
Realized value of hedges	189				13		202

Total realized gross margin	767		91	41	95		994
Unrealized gross margin	208			(13)	(16)		179
Total gross margin(1)	$ 975	$	$ 91	$ 28	$ 79	$	$ 1,173

(1) Gross margin excludes depreciation and amortization.

Energy represents gross margin from the generation of electricity, fuel sales and purchases at market prices, fuel handling, steam sales, 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 (which we had at Potrero 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.

Table of Contents

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 nine months ended September 30, 2011. The following table summarizes power generation volumes by segment:

	September 30, Nine Months Ended 2011	September 30, September 30, 2010 (in gigawatt hours)	September 30, Increase/ (Decrease)	September 30, Increase/ (Decrease)
Eastern PJM:				
Baseload	9,147	11,094	(1,947)	(18)%
Intermediate	744	1,065	(321)	(30)%
Peaking	114	191	(77)	(40)%
Total Eastern PJM	10,005	12,350	(2,345)	(19)%
Western PJM/MISO:				
Baseload	13,189		13,189	N/A
Intermediate	2,884		2,884	N/A
Peaking	76		76	N/A
Total Western PJM/MISO	16,149		16,149	N/A
California:				
Intermediate	330	466	(136)	(29)%
Peaking	2	(1)	3	300%
Total California	332	465	(133)	(29)%
Other Operations:				
Baseload	1,536	1,120	416	37%
Intermediate	248	382	(134)	(35)%
Peaking	314	6	308	N/A
Total Other Operations	2,098	1,508	590	39%
Total	28,584	14,323	14,261	100%

The total increase in power generation volumes during the nine months ended September 30, 2011, as compared to the same period in 2010, was primarily the result of the following:

Eastern PJM. The decrease in our baseload and intermediate generation volumes was primarily as a result of contracting dark spreads and spark spreads.

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

California. The decrease in our intermediate generation volumes was primarily the result of the shutdown of the Potrero generating facility, partially offset by the addition of the RRI Energy generating facilities as a result of the Merger.

Other Operations. The increase in our baseload and peaking generation volumes was primarily related to the addition of the RRI Energy generating facilities as a result of the Merger, offset in part by a decrease in our baseload and intermediate generation for our facilities located in the Northeast as a result of a reduction in our available capacity at our Bowline generating facility, an outage at one of our generating facilities and contracting spark spreads in New England.

Table of Contents

Eastern PJM

Our Eastern PJM segment includes eight generating facilities with total net generating capacity of 6,336 MW at September 30, 2011 and four generating facilities with total net generating capacity of 5,204 MW at September 30, 2010.

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

	September 30, Nine Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 175	$ 321	$ (146)
Contracted and capacity	239	257	(18)
Realized value of hedges	178	189	(11)
Total realized gross margin	592	767	(175)
Unrealized gross margin	(63)	208	(271)
Total gross margin (excluding depreciation and amortization)	529	975	(446)
Operating Expenses:			
Operations and maintenance	351	346	5
Depreciation and amortization	101	105	(4)
Impairment losses	95		95
Gain on sales of assets, net		(3)	3
Total operating expenses, net	547	448	99
Operating income	$ (18)	$ 527	$ (545)

Gross Margin

The decrease of $175 million in realized gross margin was principally a result of the following:

- a decrease of $146 million in energy, primarily as a result of a decrease in generation volumes as a result of contracting dark spreads and spark spreads;
- a decrease of $18 million in contracted and capacity, primarily as a result of a $53 million decrease from lower capacity prices and a $7 million decrease from ancillary services, offset by $42 million from the addition of the RRI Energy generating facilities as a result of the Merger; and
- a decrease of $11 million in realized value of hedges, primarily as a result of a $45 million decrease in power hedges primarily resulting from prices, offset in part by a $34 million increase in our coal hedges resulting from prices.

Our unrealized gross margin for both periods reflects the following:

unrealized losses of $63 million during the nine months ended September 30, 2011, which included $155 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, offset by a $92 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 $208 million during the nine months ended September 30, 2010, which included a $421 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset in part by the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value was further offset by $213 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Table of Contents

Operating Expenses

The increase of $99 million in operating expenses was principally the result of the following:

- an increase of $95 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR; and

- an increase of $5 million in operations and maintenance expense primarily as a result of (a) a $30 million accrual for remediation costs at our Maryland ash facilities (which includes a tentative $1.9 million civil penalty), (b) $12 million of major litigation costs, net of recoveries and (c) the addition of the RRI Energy generating facilities as a result of the Merger. The increases were partially offset by decreases resulting from (a) $14 million as a result of the repeal of the Montgomery County CO_2 levy, including $8 million related to a refund received in the third quarter of 2011 of CO_2 levies paid in 2010, (b) a change in the allocation methodology for overhead costs as a result of the Merger and (c) a $6 million decrease resulting from changes in asset retirement obligation assumptions; offset by

- a decrease of $4 million in depreciation and amortization expense related to a reduction in the carrying value of the Dickerson and Potomac River generating facilities as a result of impairment losses in the fourth quarter of 2010, partially offset by the addition of the RRI Energy generating facilities as a result of the Merger.

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 September 30, 2011.

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

	September 30, Nine Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 249	$	$ 249
Contracted and capacity	246		246
Realized value of hedges	19		19
Total realized gross margin	514		514
Unrealized gross margin	10		10
Total gross margin (excluding depreciation and amortization)	524		524
Operating Expenses:			
Operations and maintenance	368		368
Depreciation and amortization	81		81
Impairment losses	4		4
Total operating expenses, net	453		453
Operating income	$ 71	$	$ 71

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 September 30, 2011 and three generating facilities with total net generating capacity of 2,347 MW at September 30, 2010. Our California segment also includes business development and construction activities for new generation in California, including GenOn Marsh Landing.

Table of Contents

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

	September 30, Nine Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 10	$	$ 10
Contracted and capacity	173	91	82
Realized value of hedges	3		3
Total realized gross margin	186	91	95
Unrealized gross margin			
Total gross margin (excluding depreciation and amortization)	186	91	95
Operating Expenses:			
Operations and maintenance	111	53	58
Depreciation and amortization	32	23	9
Impairment losses	14		14
Gain on sales of assets, net	(5)		(5)
Total operating expenses, net	152	76	76
Operating income (loss)	$ 34	$ 15	$ 19

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. Our Potrero units were subject to RMR arrangements through February 28, 2011, the date of the shutdown. In addition, we have some units in southern California that we operate under tolling agreements with other customers. Our gross margin generally is not affected by changes in power generation volumes from facilities under such arrangements.

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

The increase of $95 million in realized gross margin was principally a result of the following:

- an increase of $82 million in contracted and capacity primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility; and

- an increase of $10 million in energy primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger.

Operating Expenses

The increase of $76 million in operating expenses was principally a result of the following:

an increase of $58 million in operations and maintenance expense related to the addition of the RRI Energy facilities as a result of the Merger, partially offset by the shutdown of the Potrero generating facility and other cost reductions;

an increase of $14 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR; and

63

Table of Contents

an increase of $9 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, partially offset by

an increase of $5 million in gain on sales of assets as a result of the sale of equipment from our Potrero generating facility.

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:

	September 30, Nine Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 65	$ 41	$ 24
Total realized gross margin	65	41	24
Unrealized gross margin	5	(13)	18
Total gross margin (excluding depreciation and amortization)	70	28	42
Operating Expenses:			
Operations and maintenance	2	7	(5)
Depreciation and amortization	2	1	1
Total operating expenses, net	4	8	(4)
Operating income	$ 66	$ 20	$ 46

Gross Margin

The increase of $24 million in realized gross margin was primarily as a result of an increase in natural gas transportation activities, proprietary trading and fuel oil management activities.

Our unrealized gross margin for both periods reflects the following:

unrealized gains of $5 million during the nine months ended September 30, 2011, which included a $3 million net increase in the value of contracts for future periods and $2 million associated with the reversal of previously recognized unrealized losses from power and fuel contracts that settled during the period; and

unrealized losses of $13 million during the nine months ended September 30, 2010, which included $63 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period, offset by a $50 million net increase in the value of contracts for future periods.

Other Operations

Our Other Operations segment consists of nine generating facilities with total net generating capacity of 5,055 MW at September 30, 2011 and four generating facilities with total net generating capacity of 2,535 MW at September 30, 2010. Other operations also includes unallocated overhead expenses and other activity that cannot be specifically identified with another segment.

Table of Contents

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

	September 30, Nine Months Ended 2011	September 30, September 30, 2010 (in millions)	September 30, Increase/ (Decrease)
Gross Margin:			
Energy	$ 18	$ 15	$ 3
Contracted and capacity	71	67	4
Realized value of hedges	2	13	(11)
Total realized gross margin	91	95	(4)
Unrealized gross margin	(11)	(16)	5
Total gross margin (excluding depreciation and amortization)	80	79	1
Operating Expenses:			
Operations and maintenance	131	64	67
Depreciation and amortization	49	28	21
Impairment losses	20		20
Gain on sales of assets, net		(1)	1
Total operating expenses, net	200	91	109
Operating income (loss)	$ (120)	$ (12)	$ (108)

Gross Margin

The decrease of $4 million in realized gross margin was principally a result of the following:

a decrease of $11 million in realized value of hedges primarily as a result of a decline in the value realized from our power and oil hedges, partially offset by

an increase of $4 million in contracted and capacity primarily as a result of the addition of the RRI Energy generating facilities as a result of the Merger, partially offset by decreases attributable to our facilities located in the Northeast resulting from lower capacity prices; and

an increase of $3 million in energy primarily as a result of increases in prices and generation volumes.

Our unrealized gross margin for both periods reflects the following:

unrealized losses of $11 million during the nine months ended September 30, 2011, which included $7 million associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period and a $4 million net decrease in the value of hedge contracts for future periods; and unrealized losses of $16 million during the nine months ended September 30, 2010 associated with the reversal of previously recognized unrealized gains from power and fuel contracts that settled during the period.

Operating Expenses

The increase of $109 million in operating expenses was principally the result of the following:

an increase of $67 million in operations and maintenance expense primarily related to (a) $48 million in merger-related costs, (b) $37 million as a result of a curtailment gain recorded in 2010 resulting from an amendment to our postretirement healthcare benefits plan covering certain of our Eastern PJM union employees and (c) the addition of the RRI Energy generating facilities as a result of the Merger. These increases were partially offset by a change in the allocation methodology for overhead costs as a result of the Merger and other cost reductions;

Table of Contents

- an increase of $21 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; and

- an increase of $20 million in impairment losses for the write-off of excess NO_x and SO_2 emissions allowances during the three months ended September 30, 2011 as a result of the CSAPR.

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 7 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 September 30, 2011 (in millions):

	September 30,
Cash and Cash Equivalents:	
GenOn (excluding GenOn Mid-Atlantic and REMA)	$ 1,600
GenOn Mid-Atlantic	84
REMA[(1)]	62
Total cash and cash equivalents	1,746
Less: cash reserved for other purposes	(13)
Total available cash and cash equivalents	1,733
Availability under GenOn credit facilities[(2)]	549
Total available cash, cash equivalents and availability under GenOn credit facilities[(2)]	$ 2,282

(1) At September 30, 2011, REMA did not satisfy the restricted payments test and therefore could not use such funds to distribute cash and make other restricted payments.

(2) 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 September 30, 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.

Table of Contents

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

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

(2) At September 30, 2011, $15 million and $35 million were outstanding under the GenOn Marsh Landing senior secured term loan, due 2017 and senior secured term loan, due 2023, respectively.

Table of Contents

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 or make other restricted payments. At September 30, 2011, GenOn Mid-Atlantic satisfied the restricted payments test. At September 30, 2011, REMA did not satisfy the restricted payments test. As a result of certain lien restrictions in its lease documentation, GenOn Mid-Atlantic has reserved $165.6 million of cash (which is included in funds on deposit on the condensed consolidated balance sheet) in respect of such liens. See note 13 to our interim financial statements.

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. On June 1, 2011, we redeemed $382 million (principal plus 3% premium) of PEDFA bonds due 2036. See note 7 to our interim financial statements.

Capital Expenditures. Our capital expenditures, excluding capitalized interest paid, during the nine months ended September 30, 2011, were $319 million. We estimate our capital expenditures, excluding capitalized interest not related to the Marsh Landing generating facility, for the period October 1, 2011 through December 31, 2013 will be $1.1 billion. 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, 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 September 30, 2011, we had $233 million of posted cash collateral and $239 million of letters of credit outstanding under our revolving credit facility, primarily to support our asset management activities, trading activities, rent reserve requirements, Marsh Landing project and other commercial arrangements. In addition, we issued $134 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.

Table of Contents

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

	September 30, September 30, 2011	September 30, December 31, 2010
	(in millions)	
Cash collateral posted energy trading and marketing	$ 194	$ 220
Cash collateral posted other operating activities	39	45
Letters of credit Marsh Landing project[1]	178	106
Letters of credit rent reserves	103	133
Letters of credit energy trading and marketing	57	96
Letters of credit other operating activities	35	38
Surety bonds[2]	42	50
Total	$ 648	$ 688

(1) Includes $134 million and $106 million of cash-collateralized letters of credit at September 30, 2011 and December 31, 2010, respectively.

(2) Includes $34 million of cash under surety bonds posted primarily with the Pennsylvania Department of Environmental Protection related to environmental obligations at September 30, 2011 and December 31, 2010.

Cash collateral posted energy trading and marketing includes initial margin held by MF Global Inc. (MF Global). See Item 3, Quantitative and Qualitative Disclosures About Market Risk Counterparty Credit Risk for a discussion of the pending liquidation of MF Global.

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

There have been no material changes outside the ordinary course of business to our debt obligations, off-balance sheet arrangements and contractual obligations from those disclosed in our 2010 Annual Report on Form 10-K and note 7 to our interim financial statements.

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 $61 million for the nine months ended September 30, 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 $454 million primarily as a result of the addition of the 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;

Interest expense. An increase in cash used of $136 million primarily as a result of debt assumed in the Merger and new debt issued as a result of the Merger. See note 7 to our interim financial statements;

Accounts payable, collateral. A decrease in cash provided of $41 million primarily as a result of less than $1 million posted by our counterparties in 2011 compared to $41 million posted by our counterparties in 2010; and

Other operating assets and liabilities. An increase in cash used of $18 million related to changes in other operating assets and liabilities compared to the same period in 2010.

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 $409 million in 2011 compared to the same period in 2010 (excluding an out-of-market contract amortization of $25 million in 2011 and lower of cost or market inventory adjustments of $20 million) primarily as a result of the addition of the 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;

- *Funds on deposit*. An increase in cash provided of $109 million primarily as a result of $4 million of additional collateral returned by our counterparties in 2011 compared to $105 million of additional collateral posted with our counterparties in 2010; and

- Inventory. An increase in cash provided of $70 million primarily related to changes in fuel oil inventory compared to the same period in 2010; and

Investing Activities. Net cash provided by investing activities increased by $1.327 billion for the nine months ended September 30, 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 $1.638 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 7 to our interim financial statements;

- *Other investing*. An increase in cash provided of $12 million primarily related to proceeds received from the sale of investments, partially offset by:

- *Payments into restricted funds on deposit*. A decrease in cash provided of $209 million primarily related to funds placed in restricted deposits as a result of our scrubber contract litigation and related liens. See note 13 to our interim financial statements; and

- *Capital expenditures*. An increase in cash used of $114 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.

Financing Activities. Net cash used in financing activities increased by $1.952 billion for the nine months ended September 30, 2011, compared to the same period in 2010. This difference was primarily a result of the repayment of long-term debt, partially offset by proceeds received to finance the construction of our Marsh Landing generating facility. See note 7 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.

70

Table of Contents

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 6 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 $615 million and $881 million at September 30, 2011 and 2010, respectively. The following tables provide a summary of the factors affecting changes (composed of the sum of the quarterly changes) in fair value of the derivative contract asset and liability accounts for the nine months ended September 30, 2011 and 2010:

	September 30, Commodity Contracts	September 30,	September 30, Other Contracts	September 30,
	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]	98	3	(46)	55
Purchases[2]				
Issuances[2]				
Settlements[3]	(160)			(160)
Fair value of portfolio of assets and liabilities at September 30, 2011	$ 644	$ (2)	$ (27)	$ 615
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]	279	59		338
Roll off of previous values[4]	(229)	(63)		(292)
Purchases[2]				
Issuances[2]				
Settlements[5]	135	(2)		133
Fair value of portfolio of assets and liabilities at September 30, 2010	$ 886	$ (5)	$	$ 881

(1) Represents the fair value, as of the end of each reporting period, of contracts entered into during each reporting period and the gains or losses attributable to contracts that existed as of the beginning of each reporting period and were still held at the end of each reporting period.
(2) Contracts entered into during each 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 reporting period.
(4) Represents the reversal of previously recognized unrealized gains and losses from the settlement of contracts during each reporting period.
(5) Represents the total cash settlements of contracts during each reporting period that existed at the beginning of each reporting period.

Table of Contents

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 September 30, 2011, the estimated net fair value of our derivative contract assets and liabilities are (asset (liability)):

Sources of Fair Value	September 30, Remainder of 2011	September 30, 2012	September 30, 2013	September 30, 2014 (in millions)	September 30, 2015	September 30, 2016 and thereafter	September 30, Total fair value
Asset Management:							
Prices actively quoted (Level 1)	$ (10)	$ (19)	$ 9	$ 10	$ 7	$ 1	$ (2)
Prices provided by other external sources (Level 2)	74	207	198	197	16		692
Prices based on models and other valuation methods (Level 3)	(7)	(37)	(1)	(1)			(46)
Total asset management	$ 57	$ 151	$ 206	$ 206	$ 23	$ 1	$ 644
Trading Activities:							
Prices actively quoted (Level 1)	$ (3)	$ (8)	$	$	$	$	$ (11)
Prices provided by other external sources (Level 2)	3	(1)	1				3
Prices based on models and other valuation methods (Level 3)	1	5					6
Total trading activities	$ 1	$ (4)	$ 1	$	$	$	$ (2)
Interest Rate:							
Prices actively quoted (Level 1)	$	$	$	$	$	$	$
Prices provided by other external sources (Level 2)		(1)	(7)	(9)	(5)	(5)	(27)
Prices based on models and other valuation methods (Level 3)							
Total interest rate	$	$ (1)	$ (7)	$ (9)	$ (5)	$ (5)	$ (27)

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 6 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 credit valuation adjustment, which is reflected as a reduction of our derivative contract assets, related to counterparty credit risk of $52 million and $21 million at September 30, 2011 and December 31, 2010, respectively.

Table of Contents

In accordance with the fair value measurements accounting guidance, we calculate a credit valuation adjustment through consideration of observable market inputs, when available. We calculate our credit valuation adjustment 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 41% of our net notional power position at September 30, 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 $5 million in our credit reserve at September 30, 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 6 to our interim financial statements for further discussion of our counterparty credit concentration risk. Also, for a discussion of the risks of non-performance by our counterparties, see the risks set forth in Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K, including, We are exposed to possible losses that may occur from the failure of a counterparty to perform according to the terms of contractual arrangements with us, particularly in connection with our non-collateralized power hedges between GenOn Mid-Atlantic and financial institutions.

MF Global, a futures contract merchant and broker/dealer entity, was one of three clearing brokers through which we held positions on The Chicago Mercantile Exchange, the Intercontinental Exchange and the Nodal Exchange. On October 31, 2011, the Securities Investor Protection Corporation announced that it initiated the liquidation of MF Global under the Securities Investor Protection Act. As of October 31, 2011, we had $12 million in our accounts with MF Global, $9 million of which was being used to cover the initial margin requirements of our open positions. Recovery of the initial margin and excess funds from MF Global will be a function of the amounts available to satisfy the claims of customers and other creditors and the priority of claims. Generally customers with commodity contracts receive priority treatment with respect to customer property. However, news reports indicate that there may be a significant shortfall in MF Global s commodity customer funds. We are in the process of evaluating our claims and will be pursuing our rights to recover amounts owed.

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 $18 million to our derivative contract assets and a change of $8 million to our derivative contract liabilities at September 30, 2011.

Debt

Some of our debt is subject to variable interest rates, including our $693 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 is 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 is 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 2014 and one that extends to 2020. Excluding our Keystone and Conemaugh generating facilities (which are not 100% owned by us) and excluding our Seward generating facility (which burns waste coal supplied by an all-requirements contract), we had exposure to three counterparties at September 30, 2011 and December 31, 2010, respectively, that each represented an exposure of more than 10% of our total coal commitments, by volume, and in aggregate represented approximately 66% and 76% of our total coal commitments at September 30, 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 6 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 September 30, 2011, and are projected to provide a $59 million benefit to our realized value of hedges through 2013 as the coal is utilized in the production of electricity.

Table of Contents

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 September 30, 2011. Based upon this assessment, our management concluded that, as of September 30, 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, processes and related internal control over financial reporting as a result of the Merger. We will continue to assess the effectiveness of our internal control over financial reporting as we execute merger integration activities.

Table of Contents

PART II

ITEM 1. LEGAL PROCEEDINGS

See note 13 to our interim unaudited condensed consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operations Environmental Matters Cross-State Air Pollution Rule.

Table of Contents

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)
4.5	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*	GenOn Energy Severance Pay Plan effective beginning December 3, 2010
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.

Table of Contents

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: November 9, 2011	By: /s/ THOMAS C. LIVENGOOD
	Thomas C. Livengood *Senior Vice President and Controller* *(Duly Authorized Officer and* *Principal Accounting Officer)*