MIRANT CORP
Form 10-Q
August 06, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2010

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: 001-16107

Mirant Corporation

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**20-3538156**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1155 Perimeter Center West, Suite 100, **Atlanta, Georgia** (Address of Principal Executive Offices)	**30338** (Zip Code)

(678) 579-5000

(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. (Check one):

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. þ Yes ¨ No

As of July 30, 2010, there were 145,539,286 shares of the registrant s Common Stock, $0.01 par value per share, outstanding.

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Glossary of Certain Defined Terms

Ancillary Services Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services include regulation service, reserves and voltage support.

APSA Asset Purchase and Sale Agreement dated June 7, 2000, between the Company and Pepco.

Bankruptcy Code United States Bankruptcy Code.

Bankruptcy Court United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division.

Baseload Generating Units Units that 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.

Cal PX California Power Exchange.

Clean Air Act Federal Clean Air Act.

Clean Water Act Federal Water Pollution Control Act.

CO2 Carbon dioxide.

Company Old Mirant prior to January 3, 2006, and New Mirant on or after January 3, 2006.

CPUC California Public Utilities Commission.

DC Circuit The United States Court of Appeals for the District of Columbia Circuit.

DWR California Department of Water Resources.

EBITDA Earnings before interest, taxes, depreciation and amortization.

EOB California Electricity Oversight Board.

EPA United States Environmental Protection Agency.

EPC Engineering, procurement and construction.

EPS Earnings (loss) per share.

Exchange Act Securities Exchange Act of 1934.

Exchange Ratio Right of Mirant Corporation stockholders to receive 2.835 shares of common stock of RRI Energy, Inc.

FASB Financial Accounting Standards Board.

FERC Federal Energy Regulatory Commission.

GAAP United States generally accepted accounting principles.

GenOn Energy GenOn Energy, Inc.

Gross Margin Operating revenue less cost of fuel, electricity and other products, excluding depreciation and amortization.

Hart-Scott-Rodino Act Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

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Hudson Valley Gas Hudson Valley Gas Corporation.

IBEW International Brotherhood of Electrical Workers.

Intermediate Generating Units Units that meet system requirements that are greater than baseload and less than peaking.

ISO Independent System Operator.

LIBOR London InterBank Offered Rate.

MC Asset Recovery MC Asset Recovery, LLC.

MDE Maryland Department of the Environment.

Merger Agreement The agreement and plan of merger into which Mirant Corporation entered with RRI Energy, Inc. and RRI Energy Holdings, Inc. on April 11, 2010.

Mirant Old Mirant prior to January 3, 2006, and New Mirant on or after January 3, 2006.

Mirant Americas Energy Marketing Mirant Americas Energy Marketing, LP.

Mirant Americas Generation Mirant Americas Generation, LLC.

Mirant Bowline Mirant Bowline, LLC.

Mirant California Mirant California, LLC.

Mirant Chalk Point Mirant Chalk Point, LLC.

Mirant Delta Mirant Delta, LLC.

Mirant Energy Trading Mirant Energy Trading, LLC.

Mirant Lovett Mirant Lovett, LLC, owner of the former Lovett generating facility, which was shut down on April 19, 2008, and has been demolished.

Mirant Marsh Landing Mirant Marsh Landing, LLC.

Mirant MD Ash Management Mirant MD Ash Management, LLC.

Mirant Mid-Atlantic Mirant Mid-Atlantic, LLC and, except where the context indicates otherwise, its subsidiaries.

Mirant New York Mirant New York, LLC.

Mirant North America Mirant North America, LLC.

Mirant NY-Gen Mirant NY-Gen, LLC sold by the Company in the second quarter of 2007.

Mirant Potomac River Mirant Potomac River, LLC.

Mirant Potrero Mirant Potrero, LLC.

Mirant Services Mirant Services, LLC.

MW Megawatt.

MWh Megawatt hour.

NAAQS National ambient air quality standard.

Net Capacity Factor Actual production of electricity as a percentage of net dependable capacity to produce electricity.

New Mirant Mirant Corporation on or after January 3, 2006.

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NOL Net operating loss.

NOV Notice of violation.

NOx Nitrogen oxides.

NSR New source review.

NYISO New York Independent System Operator.

NYMEX New York Mercantile Exchange.

NYSE New York Stock Exchange.

Old Mirant MC 2005, LLC, known as Mirant Corporation prior to January 3, 2006.

OTC Over-the-Counter.

Ozone Season The period between May 1 and September 30 of each year.

Peaking Generating Units Units used to meet demand requirements during the periods of greatest or peak load on the system.

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 the Company s emergence from bankruptcy protection on January 3, 2006.

PPA Power purchase agreement.

Reserve Margin Excess capacity over peak demand.

RGGI Regional Greenhouse Gas Initiative.

RMR Reliability-must-run.

RRI Energy RRI Energy, Inc.

RTO Regional Transmission Organization.

Scrubbers Flue gas desulfurization emissions controls.

Securities Act Securities Act of 1933, as amended.

Series A Warrants Warrants issued on January 3, 2006, with an exercise price of $21.87 and expiration date of January 3, 2011.

Series B Warrants Warrants issued on January 3, 2006, with an exercise price of $20.54 and expiration date of January 3, 2011.

SO2 Sulfur dioxide.

Spark Spread The difference between the price received for electricity generated compared to the market price of the natural gas required to produce the electricity.

VaR Value at risk.

VIE Variable interest entity.

Virginia DEQ Virginia Department of Environmental Quality.

Wrightsville Wrightsville, Arkansas power generating facility sold by the Company in the third quarter of 2005.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements involve known and unknown risks and uncertainties and relate to future events, our future financial performance or our projected business results. In some cases, one can identify forward-looking statements by terminology such as may, will, should, expect, intend, seek, plan, think, anticipate 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:

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, 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;

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

environmental regulations (including the cumulative effect of many such regulations) that restrict our ability or render it uneconomic to operate our business, including regulations related to the emission of CO_2 and other greenhouse gases;

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 off-site of ash and other byproducts;

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

continued 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 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 rules and regulations governing derivative financial instruments;

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 rules and regulations governing derivative financial instruments, which may affect our ability to engage in asset management, proprietary trading and fuel oil management activities as expected, or result in material gains or losses from open positions;

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

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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;

the expected timing and likelihood of completion of the proposed merger with RRI Energy, including the timing, receipt and terms and conditions of required stockholder, governmental and regulatory approvals that may reduce anticipated benefits or cause the parties to abandon the merger; the ability of the parties to arrange debt financing in an amount sufficient to fund the refinancing contemplated in, and on terms consistent with, the Merger Agreement; the diversion of management s time and attention from our ongoing business during the time we are seeking to complete the merger; the ability to maintain relationships with employees, customers and suppliers; the ability to integrate successfully the businesses and realize cost savings and any other synergies; and the risk that credit ratings of the combined company or its subsidiaries may be different from what the companies expect;

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;

changes in the rules used to calculate capacity, energy and ancillary services payments;

legal and political challenges to the rules used to calculate capacity, energy and ancillary services payments;

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

our ability to enter into intermediate and long-term contracts to sell power or to hedge 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;

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

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

the potential limitation or loss of our income tax NOLs notwithstanding a continuation of our stockholder rights plan;

our ability to borrow additional funds and access capital markets;

strikes, union activity or labor unrest;

our ability to obtain or develop 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;

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

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

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- our ability to execute our development plan in respect of our Marsh Landing generating facility, including obtaining the permits necessary for construction and operation of the generating facility, securing the necessary project financing for construction 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 Mid-Atlantic market;

- the ability of lenders under Mirant North America s revolving credit facility to perform their obligations;

- 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;

- 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 Mirant North America contained in its financing agreements and restrictions on Mirant Mid-Atlantic contained in its leveraged 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 or monitor provisions of our loan agreements and debt may lead to a breach and, if not remedied, result in an event of default thereunder, which would limit access to needed capital and damage our reputation and relationships with financial institutions; and

- the disposition of the pending litigation described in this Form 10-Q.

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

Factors that Could Affect Future Performance

We undertake no obligation to update publicly or revise any forward-looking statements to reflect events or circumstances that may arise after the date of this report.

In addition to the discussion of certain risks in Management s Discussion and Analysis of Results of Operations and Financial Condition and the accompanying Notes to Mirant s unaudited condensed consolidated financial statements, other factors that could affect our future performance (business, results of operations or financial condition and cash flows) are set forth in our 2009 Annual Report on Form 10-K and elsewhere in this Form 10-Q and are incorporated herein by reference.

Certain Terms

As used in this report, unless the context requires otherwise, we, us, our, the Company and Mirant refer to Old Mirant and its subsidiaries pr to January 3, 2006 and to New Mirant and its subsidiaries on or after January 3, 2006.

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MIRANT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in millions, except per share data)			
Operating revenues (including unrealized gains (losses) of $(231) million, $(44) million, $132 million and $211 million, respectively)	**$ 244**	$ 496	**$ 1,124**	$ 1,374
Cost of fuel, electricity and other products (including unrealized losses (gains) of $109 million, $(30) million, $120 million and $(29) million, respectively)	**272**	150	**479**	421
Gross Margin (excluding depreciation and amortization)	**(28)**	346	**645**	953
Operating Expenses:				
Operations and maintenance	**132**	114	**298**	276
Depreciation and amortization	**53**	36	**104**	72
Gain on sales of assets, net	**(1)**	(2)	**(3)**	(17)
Total operating expenses, net	**184**	148	**399**	331
Operating Income (Loss)	**(212)**	198	**246**	622
Other Expense (Income), net:				
Interest expense	**49**	34	**99**	72
Interest income		(1)		(3)
Equity in income of affiliates		1		1
Other, net	**1**	1	**2**	1
Total other expense, net	**50**	35	**101**	71
Income (Loss) Before Income Taxes	**(262)**	163	**145**	551
Provision for income taxes	**1**		**1**	8
Net Income (Loss)	**$ (263)**	$ 163	**$ 144**	$ 543
Basic and Diluted EPS:				
Basic EPS	**$ (1.81)**	$ 1.12	**$ 0.99**	$ 3.74
Diluted EPS	**$ (1.81)**	$ 1.12	**$ 0.99**	$ 3.74
Weighted average shares outstanding	**145**	145	**145**	145
Effect of dilutive securities			**1**	
Weighted average shares outstanding assuming dilution	**145**	145	**146**	145

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

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MIRANT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	At June 30, 2010	At December 31, 2009
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 1,849**	$ 1,953
Funds on deposit	**197**	181
Receivables, net	**258**	412
Derivative contract assets	**1,687**	1,416
Inventories	**310**	241
Prepaid expenses	**124**	144
Total current assets	**4,425**	4,347
Property, Plant and Equipment, net	**3,643**	3,633
Noncurrent Assets:		
Intangible assets, net	**166**	171
Derivative contract assets	**751**	599
Deferred income taxes	**398**	376
Prepaid rent	**358**	304
Other	**105**	98
Total noncurrent assets	**1,778**	1,548
Total Assets	**$ 9,846**	$ 9,528
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	**$ 563**	$ 75
Accounts payable and accrued liabilities	**546**	718
Derivative contract liabilities	**1,440**	1,150
Deferred income taxes	**398**	376
Other	**5**	4
Total current liabilities	**2,952**	2,323
Noncurrent Liabilities:		
Long-term debt, net of current portion	**1,999**	2,556
Derivative contract liabilities	**284**	163
Pension and postretirement obligations	**70**	113
Other	**69**	58
Total noncurrent liabilities	**2,422**	2,890
Commitments and Contingencies		
Stockholders Equity:		

Preferred stock, par value $.01 per share, authorized 100,000,000 shares, no shares issued at June 30, 2010 and December 31, 2009		
Common stock, par value $.01 per share, authorized 1.5 billion shares, issued 312,000,533 shares and 311,230,486 shares at June 30, 2010 and December 31, 2009, respectively, and outstanding 145,537,553 shares and 144,946,815 shares at June 30, 2010 and December 31, 2009, respectively	**3**	3
Treasury stock, at cost, 166,462,980 shares and 166,283,671 shares at June 30, 2010 and December 31, 2009, respectively	**(5,336)**	(5,334)
Additional paid-in capital	**11,437**	11,427
Accumulated deficit	**(1,584)**	(1,728)
Accumulated other comprehensive loss	**(48)**	(53)
Total stockholders equity	**4,472**	4,315
Total Liabilities and Stockholders Equity	**$ 9,846**	$ 9,528

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

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MIRANT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME (UNAUDITED)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Accumulated Deficit (in millions)	Accumulated Other Comprehensive Loss	Total Stockholders Equity
Balance, December 31, 2009	$ 3	$ (5,334)	$ 11,427	$ (1,728)	$ (53)	$ 4,315
Share repurchases		(2)				(2)
Stock-based compensation			9			9
Exercises of stock options			1			1
Total stockholders equity before other comprehensive income						4,323
Net income				144		144
Pension and other postretirement benefits					5	5
Total other comprehensive income						149
Balance, June 30, 2010	**$ 3**	**$ (5,336)**	**$ 11,437**	**$ (1,584)**	**$ (48)**	**$ 4,472**

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

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MIRANT CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in millions)	
Cash Flows from Operating Activities:		
Net income	**$ 144**	$ 543
Adjustments to reconcile net income and changes in other operating assets and liabilities to net cash provided by operating activities:		
Depreciation and amortization	**106**	75
Gain on sales of assets, net	**(3)**	(17)
Unrealized gains on derivative contracts, net	**(12)**	(240)
Stock-based compensation expense	**8**	16
Postretirement benefits curtailment gain	**(37)**	
Lower of cost or market inventory adjustments	**20**	22
Equity in income of affiliates		1
Other, net	**(3)**	
Funds on deposit	**6**	30
Changes in other operating assets and liabilities	**(79)**	(46)
Total adjustments	**6**	(159)
Net cash provided by operating activities of continuing operations	**150**	384
Net cash provided by operating activities of discontinued operations	**4**	4
Net cash provided by operating activities	**154**	388
Cash Flows from Investing Activities:		
Capital expenditures	**(160)**	(378)
Proceeds from the sales of assets	**3**	17
Capital contributions		(5)
Restricted deposit payments and other	**(31)**	2
Net cash used in investing activities	**(188)**	(364)
Cash Flows from Financing Activities:		
Repayments of long-term debt	**(69)**	(41)
Share repurchases	**(2)**	(1)
Proceeds from exercises of stock options	**1**	
Net cash used in financing activities	**(70)**	(42)
Net Decrease in Cash and Cash Equivalents	**(104)**	(18)
Cash and Cash Equivalents, beginning of period	**1,953**	1,831
Cash and Cash Equivalents, end of period	**$ 1,849**	$ 1,813

Supplemental Cash Flow Disclosures:

Cash paid for interest, net of amounts capitalized	**$**	**92**	$	63
Cash paid for income taxes	**$**	**2**	$	3
Cash paid for claims and professional fees from bankruptcy	**$**		$	1

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

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MIRANT CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

A. Description of Business and Accounting and Reporting Policies

Mirant is a competitive energy company that produces and sells electricity in the United States. The Company owns or leases 10,076 MW of net electric generating capacity in the Mid-Atlantic and Northeast regions and in California. Mirant also operates an integrated asset management and energy marketing organization based in Atlanta, Georgia.

Proposed Merger with RRI Energy

On April 11, 2010, Mirant entered into the Merger Agreement with RRI Energy and RRI Energy Holdings, Inc. (Merger Sub), a direct and wholly-owned subsidiary of RRI Energy. Upon the terms and subject to the conditions set forth in the Merger Agreement, which has been unanimously approved by each of the boards of directors of Mirant and RRI Energy, Merger Sub will merge with and into Mirant, with Mirant continuing as the surviving corporation and a wholly-owned subsidiary of RRI Energy. The merger is intended to qualify as a tax-free reorganization under the Internal Revenue Code of 1986, as amended, so that none of RRI Energy, Merger Sub, Mirant or any of the Mirant stockholders generally will recognize any gain or loss in the transaction, except that Mirant stockholders will recognize gain with respect to cash received in lieu of fractional shares of RRI Energy common stock. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Mirant common stock, including grants of restricted common stock, will automatically be converted into shares of common stock of RRI Energy based on the Exchange Ratio. Additionally, upon the closing of the merger, RRI Energy will be renamed GenOn Energy. Mirant stock options and other equity awards will generally convert upon completion of the merger into stock options and equity awards with respect to RRI Energy common stock, after giving effect to the Exchange Ratio. As a result of the merger, Mirant stockholders will own approximately 54% of the equity of the combined company and RRI Energy stockholders will own approximately 46%.

Completion of the merger is subject to various customary conditions, including, among others, (i) approval by RRI Energy stockholders of the issuance of RRI Energy common stock in the merger, (ii) adoption of the Merger Agreement by Mirant stockholders, (iii) effectiveness of the registration statement for the RRI Energy common stock to be issued in the merger, (iv) approval of the listing on the NYSE of the RRI Energy common stock to be issued in the merger, (v) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (vi) receipt of all required regulatory approvals and (vii) consummation by GenOn Energy of debt financings in an amount sufficient to fund the refinancing transactions contemplated by, and on terms consistent with, the Merger Agreement.

Among the refinancing transactions noted above, the completion of the merger is conditioned on GenOn Energy consummating certain debt financing transactions, including securing a new revolving credit facility. The new GenOn Energy debt financing and revolving credit facility will be used, in part, to redeem the Mirant North America senior notes and to repay and terminate the Mirant North America term loan and revolving credit facility. See Note D for additional information on Mirant North America s debt.

Mirant and RRI Energy are in the process of arranging mutually acceptable debt financing as contemplated under the Merger Agreement. Mirant, together with RRI Energy, have entered into agreements pursuant to which financial institutions have committed to provide a $750 million to $1.0 billion five-year revolving credit facility, subject to customary conditions to closing, including:

- the consummation of the merger;

- the receipt of at least $1.9 billion in gross cash proceeds from the issuance of senior unsecured notes and term loan borrowings; and

- the closing of the credit facility on or before December 31, 2010.

The revolving credit facility and term loan facility, and the subsidiary guarantees thereof, will be senior secured obligations of RRI Energy (proposed to be renamed GenOn Energy in connection with the merger) and certain of its subsidiaries; provided, however, that Mirant Americas Generation s subsidiaries (other than Mirant Mid-Atlantic and Mirant Energy Trading and their subsidiaries) will guarantee the revolving credit facility and term loan only to the extent permitted under the indenture for the senior notes of Mirant Americas Generation. The participating financial institutions, or affiliates thereof, have also agreed:

- to use commercially reasonable efforts to arrange a syndication of a $500 million term loan; and

- to act as underwriters or placement agents in connection with the proposed offering of senior unsecured notes.

Mirant and RRI Energy anticipate closing the proposed note offering into escrow. Upon consummation of the merger and satisfaction of the other escrow conditions, such notes will be senior unsecured obligations of GenOn Energy.

Both Mirant and RRI Energy are subject to restrictions on their ability to solicit alternative acquisition proposals, provide information and engage in discussions with third parties, except under limited circumstances to permit Mirant s and RRI Energy s boards of directors to comply with their fiduciary duties. The Merger Agreement contains certain termination rights for both Mirant and RRI Energy, and further provides that, upon termination of the Merger Agreement under specified circumstances, Mirant or RRI Energy may be required to pay the other a termination fee of either $37.15 million or $57.78 million. Further information concerning the proposed merger was included in a joint proxy statement/prospectus contained in the registration statement on Form S-4 filed by RRI Energy with the SEC on May 28, 2010, and amended on July 6, 2010.

On July 15, 2010, Mirant and RRI Energy each received a request for additional information (commonly referred to as a second request) from the Antitrust Division of the United States Department of Justice under the Hart-Scott-Rodino Act with respect to the merger. On July 20, 2010, the New York State Public Service Commission issued an order declaring that it will not further review the merger. On August 2, 2010, the FERC issued an order approving the merger.

Provided neither has experienced an ownership change between December 31, 2009, and the closing date of the merger, each of Mirant and RRI Energy is expected separately to experience an ownership change, as defined in Section (§) 382 of the Internal Revenue Code of 1986, on the merger date as a consequence of the merger. Immediately following the merger, Mirant and RRI Energy will be members of the same consolidated federal income tax group. The ability of this consolidated tax group to deduct the pre-merger NOL carry forwards of Mirant and RRI Energy against the post-merger taxable income of the group will be substantially limited as a result of these ownership changes.

The merger is expected to be completed by the end of 2010. Prior to the completion of the merger, Mirant and RRI Energy will continue to operate as independent companies. Except for specific references to the proposed merger and the associated debt financing transactions, the disclosures contained in this report on Form 10-Q relate solely to Mirant.

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Mid-Atlantic Collective Bargaining Agreement

During the second quarter of 2010, the Company entered into a new collective bargaining agreement with its employees represented by IBEW Local 1900. The Company s previous collective bargaining agreement expired on June 1, 2010. The new agreement has a five-year term expiring on June 1, 2015. As part of the new agreement, the Company is required to provide additional retirement contributions through the defined contribution plan currently sponsored by Mirant Services, increases in pay and other benefits. In addition, the new agreement provides for a change to the postretirement healthcare benefit plan covering Mid-Atlantic union employees to eliminate employer-provided healthcare subsidies through a gradual phase-out. See Note F for further information on the curtailment of postretirement healthcare benefits.

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of Mirant and its wholly-owned subsidiaries have been prepared in accordance with GAAP for interim financial information and with the instructions for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. For further information, refer to the consolidated financial statements and notes thereto included in the Company s 2009 Annual Report on Form 10-K.

The accompanying unaudited condensed consolidated financial statements include the accounts of Mirant and its wholly-owned and controlled majority-owned subsidiaries. The consolidated financial statements have been prepared from records maintained by Mirant and its subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. As of June 30, 2010, substantially all of Mirant s subsidiaries are wholly-owned and located in the United States.

The preparation of the unaudited condensed consolidated financial statements in conformity with GAAP requires management to make various estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the unaudited condensed consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. Certain prior period amounts have been reclassified to conform to the current period financial statement presentation.

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

MC Asset Recovery

MC Asset Recovery, although wholly-owned by Mirant, is governed by managers who are independent of Mirant and its other subsidiaries. MC Asset Recovery is considered a VIE because of the Company s potential tax obligations which could arise from potential recoveries from legal actions that MC Asset Recovery is pursuing. Prior to January 1, 2010, under previous accounting guidance, Mirant was considered the primary beneficiary of MC Asset Recovery and included the VIE in the Company s consolidated financial statements. Based on the revised guidance related to accounting for VIEs that became effective on January 1, 2010, the Company reassessed its relationship with MC Asset Recovery and determined that the Company is no longer deemed to be the primary beneficiary. The characteristics of a primary beneficiary, as defined in the accounting

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guidance are: (a) the entity must have the power to direct the activities or make decisions that most significantly affect the VIE s economic performance and (b) the entity must have an obligation to absorb losses or receive benefits that could be significant to the VIE. As MC Asset Recovery is governed by an independent Board of Managers that has sole power and control over the decisions that affect MC Asset Recovery s economic performance, the Company does not meet the characteristics of a primary beneficiary. Additionally, the Company no longer has any obligation to provide funding to MC Asset Recovery. However, under the Plan, the Company is responsible for the taxes owed, if any, on any net recoveries up to $175 million obtained by MC Asset Recovery. The Company currently retains any tax obligations arising from the next approximately $74 million of potential recoveries by MC Asset Recovery. As a result of the initial application of this accounting guidance, the Company deconsolidated MC Asset Recovery effective January 1, 2010, and adjusted prior periods to conform to the current presentation. See Note K for further discussion of MC Asset Recovery.

At June 30, 2010 and December 31, 2009, MC Asset Recovery had current assets and current liabilities of $37 million and $39 million, respectively, which are not included in the Company s unaudited condensed consolidated balance sheets. For both the three and six months ended June 30, 2010, MC Asset Recovery had operations and maintenance expense of less than $1 million. For both the three and six months ended June 30, 2009, MC Asset Recovery had operations and maintenance expense of $1 million, which is reflected in equity in income of affiliates in the Company s unaudited condensed consolidated statements of operations. The net effect of deconsolidation on the unaudited condensed consolidated statement of cash flows for the six months ended June 30, 2009, was a net reduction of $47 million in net cash provided by operating activities and a $5 million increase in net cash used in investing activities resulting in a total decrease in cash and cash equivalents of $52 million. There was no effect on the Company s unaudited condensed consolidated statement of cash flows for the six months ended June 30, 2010.

Inventories

Inventories consist primarily of fuel oil, coal, materials and supplies and purchased emissions allowances. Inventory is generally stated at the lower of cost or market value and is expensed on a weighted average cost basis. Fuel inventory is removed from the inventory account as it is used in the generation of electricity or sold to third parties. Materials and supplies are removed from the inventory account when they are used for repairs, maintenance or capital projects. Purchased emissions allowances are removed from inventory and charged to cost of fuel, electricity and other products in the accompanying unaudited condensed consolidated statements of operations as they are utilized for emissions volumes.

Inventories were comprised of the following (in millions):

	At June 30, 2010	At December 31, 2009
Fuel inventory:		
Fuel oil	$ 167	$ 99
Coal	47	52
Other	1	1
Materials and supplies	69	66
Purchased emissions allowances	26	23
Total inventories	$ 310	$ 241

Impairment of Long-Lived Assets

Mirant evaluates long-lived assets, such as property, plant and equipment and purchased intangible assets subject to amortization, for impairment whenever events or changes in circumstances indicate that the carrying 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. In the second quarter of 2010, Mirant evaluated the Dickerson generating facility for impairment, but did not record an impairment charge. See Note C for further discussion.

Capitalization of Interest Cost

Mirant capitalizes interest on projects during their construction period. The Company determines which debt instruments represent a reasonable measure of the cost of financing construction in terms of interest costs incurred that otherwise could have been avoided. These debt instruments and associated interest costs are included in the calculation of the weighted average interest rate used for determining the capitalization rate. Once a project is placed in service, capitalized interest, as a component of the total cost of the construction, is amortized over the estimated useful life of the asset constructed.

For the three and six months ended June 30, 2010 and 2009, the Company incurred the following interest costs (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Total interest costs	$ 50	$ 52	$ 102	$ 105
Capitalized and included in property, plant and equipment, net	(1)	(18)	(3)	(33)
Interest expense	$ 49	$ 34	$ 99	$ 72

The amounts of capitalized interest above include interest accrued. For the three and six months ended June 30, 2010, cash paid for interest was $93 million and $95 million, respectively, of which $3 million and $3 million, respectively, was capitalized. For the three and six months ended June 30, 2009, cash paid for interest was $93 million and $96 million, respectively, of which $31 million and $33 million, respectively, was capitalized.

Development Costs

Mirant capitalizes project development costs for generating facilities once it is probable that the project will be completed. These costs include professional fees, permits and other third party costs directly associated with the development of a new project. The capitalized costs are depreciated over the life of the asset or charged to operating expense if the completion of the project is no longer probable. Project development costs are expensed when incurred until the probable threshold is met. The Company began capitalizing project development costs related to the Marsh Landing generating facility upon signing the PPA with PG&E on September 2, 2009. As of June 30, 2010, the Company has capitalized approximately $3 million of project development costs related to the Marsh Landing generating facility.

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Recently Adopted Accounting Guidance

On June 12, 2009, the FASB issued guidance which requires the Company to perform an analysis to determine whether the Company s variable interest gives it a controlling financial interest in a VIE. This analysis should identify the primary beneficiary of a VIE. This guidance also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a VIE and enhances the disclosures to provide more information regarding the Company s involvement in a VIE. This guidance is effective for fiscal years beginning after November 15, 2009. The Company adopted this accounting guidance on January 1, 2010, and as a result, deconsolidated MC Asset Recovery. See Note K for further details on MC Asset Recovery.

On January 21, 2010, the FASB issued guidance that enhances the disclosures for fair value measurements. The guidance requires the Company to disclose separately the amount of significant transfers between Level 1 and Level 2 of the fair value hierarchy, the reasons for the significant transfers, the valuation techniques and inputs used and the classes of assets and liabilities accounted for at fair value on a recurring basis. The Company adopted this accounting guidance for the quarter ended March 31, 2010. See Note B for additional information on fair value measurements.

On February 25, 2010, the FASB issued guidance that amends its requirement for public companies to disclose the date through which the Company has evaluated subsequent events and whether that date represents the date the financial statements were issued or were available to be issued. The Company adopted the subsequent event disclosure requirements for the quarter ended March 31, 2010, and the adoption had no effect on the Company s unaudited condensed consolidated statements of operations, financial position or cash flows. The Company continues to evaluate subsequent events through the date when the financial statements are issued.

New Accounting Guidance Not Yet Adopted at June 30, 2010

On January 21, 2010, the FASB issued guidance that requires a reconciliation for Level 3 fair value measurements, including presenting separately the amounts of purchases, issuances and settlements on a gross basis. The Company currently discloses the amounts of purchases, issuances and settlements on a net basis within its roll forward of Level 3 fair value measurements in Note B. These disclosure requirements are effective for fiscal years beginning after December 15, 2010. The Company will present these disclosures in its Form 10-Q for the quarter ended March 31, 2011.

B. Financial Instruments

Derivative Financial Instruments

In connection with the business of generating electricity, the Company is exposed to energy commodity price risk associated with the acquisition of fuel and emissions allowances needed to generate electricity, the price of electricity produced and sold and the fair value of fuel inventories. In addition, the open positions in the Company s trading activities, comprised of proprietary trading and fuel oil management activities, expose it to risks associated with changes in energy commodity prices. The Company, through its asset management activities, enters 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. The Company s proprietary trading activities also utilize similar derivative financial instruments in markets where the Company has a physical presence to attempt to generate incremental gross margin. The Company s fuel oil management activities use derivative financial instruments to hedge economically the fair value of the Company s physical fuel oil inventories and to optimize the approximately three million barrels of storage capacity that the Company owns or leases.

Changes in the fair value and settlements of derivative financial instruments used to hedge electricity economically are reflected in operating revenue, and changes in the fair value and settlements of derivative financial instruments used to hedge fuel economically are reflected in cost of fuel, electricity and other products in the accompanying unaudited condensed consolidated statements of operations.

In May 2010, the Company concluded that it could no longer assert that physical delivery is probable for many of its coal agreements. The conclusion was based on expected generation levels, changes observed in the coal markets and substantial progress in the construction of the Company s coal blending facility at its Morgantown generating facility that will allow for greater flexibility of the Company s coal supply. Because the Company can no longer assert that physical delivery of coal from these agreements is probable, the Company is required to apply fair value accounting for these contracts in the current period and prospectively. The Company s coal agreements requiring the application of fair value accounting represented a net derivative contract liability of approximately $98 million at June 30, 2010 in the accompanying unaudited condensed consolidated balance sheet.

Changes in the fair value and settlements of derivative contracts for trading activities, comprised of proprietary trading and fuel oil management, are recorded on a net basis as operating revenue in the accompanying unaudited condensed consolidated statements of operations. As of June 30, 2010, the Company does not have any derivative financial instruments for which hedge accounting has been elected and option contracts comprise less than 1% of the Company s net derivative contract assets.

The Company also considers risks associated with interest rates, counterparty credit and Mirant s own non-performance risk when valuing its derivative financial instruments. The nominal value of the derivative contract assets and liabilities is discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of the Company s transactions being valued.

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The following table presents the fair value of each class of derivative financial instruments related to commodity price risk (in millions):

Commodity Derivative Contracts	Balance Sheet Location	Fair Value at June 30, 2010	Fair Value at December 31, 2009
Asset management:			
Power	Derivative contract assets	$ 1,238	$ 1,178
Fuel	Derivative contract assets	35	26
Total asset management		1,273	1,204
Trading activities	Derivative contract assets	1,165	811
Total derivative contract assets		2,438	2,015
Asset management:			
Power	Derivative contract liabilities	(420)	(488)
Fuel	Derivative contract liabilities	(143)	(15)
Total asset management		(563)	(503)
Trading activities	Derivative contract liabilities	(1,161)	(810)
Total derivative contract liabilities		(1,724)	(1,313)
Asset management, net:			
Power		818	690
Fuel		(108)	11
Total asset management		710	701
Trading activities, net		4	1
Total derivative contracts, net		$ 714	$ 702

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

Commodity Derivative Contracts	Location of Net Gains (Losses) Recognized in Income	Amount of Net Gains (Losses) Recognized in Income for the Three Months Ended June 30, 2010 Realized	Unrealized	Total	June 30, 2009 Realized	Unrealized	Total
Asset management	Operating revenues	$ 91	$ (218)	$ (127)	$ 191	$ (10)	$ 181
Trading activities	Operating revenues	(21)	(13)	(34)	46	(34)	12
Asset management	Cost of fuel, electricity and other products	(11)	(109)	(120)	(28)	30	2
Total		$ 59	$ (340)	$ (281)	$ 209	$ (14)	$ 195

Commodity Derivative Contracts	Location of Net Gains (Losses) Recognized in Income	Amount of Net Gains (Losses) Recognized in Income for the Six Months Ended June 30, 2010 Realized	Unrealized	Total	June 30, 2009 Realized	Unrealized	Total
Asset management	Operating revenues	$ 176	$ 135	$ 311	$ 327	$ 260	$ 587
Trading activities	Operating revenues	(2)	(3)	(5)	74	(49)	25
Asset management	Cost of fuel, electricity and other products	(26)	(120)	(146)	(44)	29	(15)
Total		$ 148	$ 12	$ 160	$ 357	$ 240	$ 597

The following table presents the notional quantity on long (short) positions for derivative financial instruments on a gross and net basis at June 30, 2010 (in equivalent MWh):

	Derivative Contract Assets	Notional Quantity Derivative Contract Liabilities (in millions)	Net Derivative Contracts
Commodity Type:			
Power[1]	(91)	48	(43)
Natural gas	(66)	68	2
Fuel oil	(3)	2	(1)
Coal	11	8	19
Total	(149)	126	(23)

[1] Includes MWh equivalent of natural gas transactions used to hedge power economically.

Fair Value Hierarchy

Based on the observability of the inputs used in the valuation techniques for fair value measurement, the Company is required to classify recorded fair value measurements according to the fair value hierarchy. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The fair value measurement inputs the Company uses vary from readily observable prices for exchange-traded instruments to price curves that cannot be validated through external pricing sources. The Company s financial assets and liabilities carried at fair value in the unaudited condensed consolidated financial statements are classified in three categories based on the inputs used.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls must be determined based on the lowest level input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and consideration of factors specific to the asset or liability.

The Company s transactions in Level 1 of the fair value hierarchy primarily consist of natural gas and crude oil futures traded on the NYMEX and swaps cleared against the NYMEX prices. The Company s transactions in Level 2 of the fair value hierarchy primarily include non-exchange-traded derivatives such as OTC forwards, swaps and options. The Company did not have any transfers between Levels 1 and 2 for the three and six months ended June 30, 2010. The Company s transactions in Level 3 of the fair value hierarchy primarily consist of coal agreements and financial power swaps in less liquid locations. As described earlier in this note, the Company was required to apply fair value accounting for many of its coal agreements beginning in May 2010. The fair value of these agreements is reflected in Level 3 of the fair value hierarchy as of June 30, 2010.

The following tables set forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010, by class and tenor, respectively. At June 30, 2010, the Company s only financial assets and liabilities measured at fair value on a recurring basis are derivative financial instruments.

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The following table presents financial assets and liabilities accounted for at fair value on a recurring basis as of June 30, 2010, on a gross and net basis by class (in millions):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:				
Commodity contracts asset management:				
Power	$ 4	$ 1,224	$ 10	$ 1,238
Fuel	7	3	25	35
Total commodity contracts asset management	11	1,227	35	1,273
Commodity contracts trading activities	637	501	27	1,165
Total derivative contract assets	648	1,728	62	2,438
Liabilities:				
Commodity contracts asset management:				
Power	(20)	(398)	(2)	(420)
Fuel	(17)	(1)	(125)	(143)
Total commodity contracts asset management	(37)	(399)	(127)	(563)
Commodity contracts trading activities	(652)	(501)	(8)	(1,161)
Total derivative contract liabilities	(689)	(900)	(135)	(1,724)
Net:				
Commodity contracts asset management:				
Power	(16)	826	8	818
Fuel	(10)	2	(100)	(108)
Total commodity contracts asset management	(26)	828	(92)	710
Commodity contracts trading activities, net	(15)		19	4
Total derivative contract assets and liabilities, net	$ (41)	$ 828	$ (73)	$ 714

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The following table presents financial assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2009, on a gross and net basis by class (in millions):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets:				
Commodity contracts asset management:				
Power	$ 2	$ 1,162	$ 14	$ 1,178
Fuel	11	8	7	26
Total commodity contracts asset management	13	1,170	21	1,204
Commodity contracts trading activities	374	415	22	811
Total derivative contract assets	387	1,585	43	2,015
Liabilities:				
Commodity contracts asset management:				
Power	(11)	(475)	(2)	(488)
Fuel	(14)	(1)		(15)
Total commodity contracts asset management	(25)	(476)	(2)	(503)
Commodity contracts trading activities	(368)	(433)	(9)	(810)
Total derivative contract liabilities	(393)	(909)	(11)	(1,313)
Net:				
Commodity contracts asset management:				
Power	(9)	687	12	690
Fuel	(3)	7	7	11
Total commodity contracts asset management	(12)	694	19	701
Commodity contracts trading activities, net	6	(18)	13	1
Total derivative contract assets and liabilities, net	$ (6)	$ 676	$ 32	$ 702

The following table presents net financial assets and liabilities accounted for at fair value on a recurring basis as of June 30, 2010, by tenor (in millions):

	Commodity Contracts		
	Asset Management	Trading Activities	Total
Remainder of 2010	$ 137	$ (3)	$ 134
2011	152	11	163
2012	113	(4)	109
2013	151		151
2014	157		157

Thereafter			
Total	$ 710	$ 4	$ 714

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The volumetric weighted average maturity, or weighted average tenor, of the asset management derivative contract portfolio at June 30, 2010 and December 31, 2009, was approximately 18 months and 22 months, respectively. The volumetric weighted average maturity, or weighted average tenor, of the trading derivative contract portfolio at June 30, 2010 and December 31, 2009, was approximately 10 months and 9 months, respectively.

Level 3 Disclosures

The following tables present a roll forward of fair values of net assets and liabilities categorized in Level 3 for the six months ended June 30, 2010 and 2009, and the amount included in income for the three and six months ended June 30, 2010 and 2009 (in millions):

	Commodity Contracts		
	Asset Management	**Trading Activities**	**Total**
Fair value of assets and liabilities categorized in Level 3 at January 1, 2010	$ 19	$ 13	$ 32
Total gains or losses (realized/unrealized):			
Included in income of existing contracts (or changes in net assets or liabilities)[1]	(133)	(16)	(149)
Purchases, issuances and settlements[2]	(16)	22	6
Transfers in and/or out of Level 3[3]	38		38
Fair value of assets and liabilities categorized in Level 3 at June 30, 2010	$ (92)	$ 19	$ (73)

	Commodity Contracts		
	Asset Management	**Trading Activities**	**Total**
Fair value of assets and liabilities categorized in Level 3 at January 1, 2009	$ 24	$ 22	$ 46
Total gains or losses (realized/unrealized):			
Included in income of existing contracts (or changes in net assets or liabilities)[1]	(11)	(11)	(22)
Purchases, issuances and settlements[2]	22	19	41
Transfers in and/or out of Level 3[3]			
Fair value of assets and liabilities categorized in Level 3 at June 30, 2009	$ 35	$ 30	$ 65

[1] Reflects the total gains or losses on contracts included in Level 3 at the beginning of each quarterly reporting period and at the end of each quarterly reporting period, and contracts entered into during each quarterly reporting period that remain at the end of each quarterly reporting period. Also reflects the Company s coal agreements that were initially recognized at fair value in the second quarter of 2010.

[2] Represents the total cash settlements of contracts during each quarterly reporting period that existed at the beginning of each quarterly reporting period.

[3] Denotes the total contracts that existed at the beginning of each quarterly reporting period and were still held at the end of each quarterly reporting period that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during each quarterly reporting period. Amounts reflect fair value as of the end of each quarterly reporting period.

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	Three Months Ended June 30, 2010			Six Months Ended June 30, 2010		
	Operating Revenues	Cost of Fuel	Total	Operating Revenues	Cost of Fuel	Total
Gains (losses) included in income	$ (36)	$ (113)	$ (149)	$ 2	$ (107)	$ (105)
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 June 30, 2010	$ (31)	$ (113)	$ (144)	$ 7	$ (107)	$ (100)

	Three Months Ended June 30, 2009			Six Months Ended June 30, 2009		
	Operating Revenues	Cost of Fuel	Total	Operating Revenues	Cost of Fuel	Total
Gains (losses) included in income	$ (10)	$ 3	$ (7)	$ 16	$ 3	$ 19
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 June 30, 2009	$ (10)	$ 3	$ (7)	$ 18	$ 3	$ 21

Counterparty Credit Concentration Risk

The Company is exposed to the default risk of the counterparties with which the Company transacts. The Company manages its credit risk by entering into master netting agreements and requiring counterparties to post cash collateral or other credit enhancements based on the net exposure and the credit standing of the counterparty. The Company also has non-collateralized power hedges entered into by Mirant Mid-Atlantic. These transactions are senior unsecured obligations of Mirant Mid-Atlantic and the counterparties and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. The Company s credit reserve on its derivative contract assets was $36 million and $13 million at June 30, 2010 and December 31, 2009, respectively.

At June 30, 2010 and December 31, 2009, less than $1 million and $12 million, respectively, of cash collateral posted to the Company by counterparties under master netting agreements were included in accounts payable and accrued liabilities on the unaudited condensed consolidated balance sheets.

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The Company also monitors counterparty credit concentration risk on both an individual basis and a group counterparty basis. The following tables highlight the credit quality and the balance sheet settlement exposures related to these activities (dollars in millions):

	At June 30, 2010				
Credit Rating Equivalent	**Gross Exposure Before Collateral[1]**	**Net Exposure Before Collateral[2]**	**Collateral[3]**	**Exposure Net of Collateral**	**% of Net Exposure**
Clearing and Exchange	$ 1,214	$ 94	$ 94	$	
Investment Grade:					
Financial institutions	916	718		718	79%
Energy companies	481	159	23	136	15%
Other					
Non-investment Grade:					
Financial institutions					
Energy companies	15	15	1	14	2%
Other					
No External Ratings:					
Internally-rated investment grade	24	22		22	2%
Internally-rated non-investment grade	23	21		21	2%
Not internally rated					
Total	$ 2,673	$ 1,029	$ 118	$ 911	100%

	At December 31, 2009				
Credit Rating Equivalent	**Gross Exposure Before Collateral[1]**	**Net Exposure Before Collateral[2]**	**Collateral[3]**	**Exposure Net of Collateral**	**% of Net Exposure**
Clearing and Exchange	$ 790	$ 96	$ 96	$	
Investment Grade:					
Financial institutions	997	646	12	634	81%
Energy companies	497	125	13	112	14%
Other					
Non-investment Grade:					
Financial institutions					
Energy companies					
Other					
No External Ratings:					
Internally-rated investment grade	34	27		27	4%
Internally-rated non-investment grade	8	8		8	1%
Not internally rated					
Total	$ 2,326	$ 902	$ 121	$ 781	100%

[1] Gross exposure before collateral represents credit exposure, including realized and unrealized transactions, before (a) applying the terms of master netting agreements with counterparties and (b) netting of transactions with clearing brokers and exchanges. The table excludes amounts related to contracts classified as normal purchases/normal sales and non-derivative contractual commitments that are not recorded at fair value in the unaudited condensed consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic

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risk if a counterparty does not perform. Non-performance could have a material adverse effect on the future results of operations, financial condition and cash flows.

[2] Net exposure before collateral represents the credit exposure, including both realized and unrealized transactions, after applying the terms of master netting agreements.

[3] Collateral includes cash and letters of credit received from counterparties.

The Company had credit exposure to two investment grade counterparties at June 30, 2010, and credit exposure to three investment grade counterparties at December 31, 2009, that each represented an exposure of more than 10% of total credit exposure, net of collateral and that totaled $507 million and $495 million at June 30, 2010 and December 31, 2009, respectively.

Mirant Credit Risk

The Company s standard industry contracts contain credit-risk-related contingent features such as ratings-related thresholds whereby the Company would be required to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. Additionally, some of the Company s contracts contain adequate assurance language, which is generally subjective in nature, but would most likely require the Company to post additional cash collateral or letters of credit as a result of a credit event, including a downgrade. However, as a result of the Company s current credit rating, the Company is typically required to post collateral in the normal course of business to offset completely its net liability positions, after applying the terms of master netting agreements. At June 30, 2010, the fair value of the Company s financial instruments with credit-risk-related contingent features in a net liability position was approximately $32 million for which the Company has posted collateral of $21 million, including cash and letters of credit, to offset substantially the position.

In addition, at June 30, 2010 and December 31, 2009, the Company had approximately $1 million and $25 million, respectively, of cash collateral posted with counterparties under master netting agreements that was included in funds on deposit on the unaudited condensed consolidated balance sheets.

Fair Values of Other Financial Instruments

Other financial instruments recorded at fair value include cash and interest-bearing cash equivalents. The following methods are used by Mirant to estimate the fair value of financial instruments that are not otherwise carried at fair value on the accompanying unaudited condensed consolidated balance sheets:

Notes and Other Receivables. The fair value of Mirant s notes receivable are estimated using interest rates it would receive currently for similar types of arrangements.

Long- and Short-Term Debt. The fair value of Mirant s long- and short-term debt is estimated using quoted market prices, when available.

The carrying amounts and fair values of Mirant s financial instruments are as follows (in millions):

	At June 30, 2010		At December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Notes and other receivables	$ 1	$ 1	$ 2	$ 2
Liabilities:				
Long- and short-term debt	$ 2,562	$ 2,513	$ 2,631	$ 2,559

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C. Impairments on Assets Held and Used

Dickerson Generating Facility

Background

During the second quarter of 2010, the County Council for Montgomery County, Maryland, adopted a law which will impose a levy of $5 per ton of CO2 emitted by Mirant Mid-Atlantic s Dickerson generating facility. The Company currently estimates Mirant Mid-Atlantic will incur $10 million to $15 million in levies per year as a result of the CO2 levy which will cause a decrease in the cash flows that the Dickerson generating facility is projected to earn in future periods. See Note K for additional information related to the Montgomery County Carbon Emissions Levy and the Company s legal challenge of it.

The Company viewed the adoption of the law by the Montgomery County council as a triggering event under accounting guidance because the law has caused management to review the economic viability of the Dickerson generating facility as a result of projected decreases in cash flows.

Asset Grouping

For purposes of impairment testing, a long-lived asset or assets must be grouped at the lowest level of identifiable cash flows. In performing the impairment analysis, the Company determined that the Dickerson generating facility was the lowest level for which identifiable cash flows are available. As a result, the Company included the cash flows associated with the Dickerson leased facilities as well as the owned combustion turbine units. The leased facilities are accounted for as operating leases, so only the leasehold improvements related to these facilities are recorded on the consolidated balance sheets. The most significant leasehold improvements for the Dickerson generating facility relate to capital expenditures made as part of the compliance with the Maryland Healthy Air Act.

Assumptions and Results

The Company s assessment for recoverability of the Dickerson generating facility under the accounting guidance related to the impairment of a long-lived asset involved developing scenarios for the future expected operations of the Dickerson generating facility. The scenarios related to the success of the legal challenges to the law. The sum of the probability weighted undiscounted cash flows for the Dickerson generating facility exceeded the carrying value as of June 30, 2010. As a result, the Company did not record an impairment charge. The carrying value of the Dickerson generating facility represented approximately 18% of the Company s total property, plant and equipment, net at June 30, 2010.

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D. Long-Term Debt

Long-term debt was as follows (dollars in millions):

	At June 30, 2010	At December 31, 2009	Interest Rate	Secured/ Unsecured
Long-term debt:				
Mirant Americas Generation:				
Senior notes:				
Due May 2011	$ 535	$ 535	8.30%	Unsecured
Due October 2021	450	450	8.50%	Unsecured
Due May 2031	400	400	9.125%	Unsecured
Unamortized debt premiums (discounts), net	(3)	(3)		
Mirant North America:				
Senior secured term loan, due 2010 to 2013	306	373	LIBOR + 1.75%[1]	Secured
Senior notes, due December 2013	850	850	7.375%	Unsecured
Capital leases, due 2010 to 2015	24	26	7.375% - 8.19%	
Total	2,562	2,631		
Less: current portion of long-term debt	(563)	(75)		
Total long-term debt, net of current portion	$ 1,999	$ 2,556		

[1] The weighted average interest rate for the six months ended June 30, 2010 and the year ended December 31, 2009, was 2.021% and 2.130%, respectively.

Mirant Americas Generation Senior Notes

The senior notes are senior unsecured obligations of Mirant Americas Generation having no recourse to any subsidiary or affiliate of Mirant Americas Generation. The Company reclassified the principal balance of the Mirant Americas Generation senior notes due in May 2011 from long-term debt to current portion of long-term debt at June 30, 2010.

Mirant North America Senior Secured Credit Facilities

Mirant North America, a wholly-owned subsidiary of Mirant Americas Generation, entered into senior secured credit facilities in January 2006, which are comprised of a senior secured term loan, due January 2013 and a senior secured revolving credit facility due January 2012. The senior secured term loan had an initial principal balance of $700 million, which has amortized to $306 million as of June 30, 2010. At the closing, $200 million drawn under the senior secured term loan was deposited into a cash collateral account to support the issuance of up to $200 million of letters of credit. During 2008, Mirant North America transferred to the senior secured revolving credit facility approximately $78 million of letters of credit previously supported by the cash collateral account and withdrew approximately $78 million from the cash collateral account, thereby reducing the cash collateral account to approximately $122 million. At June 30, 2010, the cash collateral balance was approximately $124 million as a result of interest earned on the invested cash balances. At June 30, 2010, there were approximately $93 million of letters of credit outstanding under the senior secured revolving credit facility and $123 million of letters of credit outstanding under the senior secured term loan cash collateral account. At June 30, 2010, $662 million was available under the senior secured revolving credit facility and less than $1 million was available under the senior secured term loan for cash draws or for the issuance of

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letters of credit. Although the senior secured revolving credit facility has lender commitments of $800 million, availability thereunder reflects a $45 million effective reduction as a result of the bankruptcy filing of Lehman Commercial Paper, Inc., a lender under the facility.

In addition to quarterly principal installments, which are currently $0.8 million, Mirant North America is required to make annual principal prepayments under the senior secured term loan equal to a specified percentage of its excess free cash flow, which is based on adjusted EBITDA less capital expenditures and as further defined in the loan agreement. On March 10, 2010, Mirant North America made a mandatory principal prepayment of approximately $66 million on the term loan. At June 30, 2010, the current estimate of the mandatory principal prepayment of the term loan in March 2011 is approximately $21 million. This amount has been reclassified from long-term debt to current portion of long-term debt at June 30, 2010.

The senior secured credit facilities are senior secured obligations of Mirant North America. In addition, certain subsidiaries of Mirant North America (not including Mirant Mid-Atlantic or Mirant Energy Trading) have jointly and severally guaranteed, as senior secured obligations, the senior secured credit facilities. The senior secured credit facilities have no recourse to any other Mirant entities.

See Note A for a discussion of the contemplated repayment of the term loan and repayment and termination of the revolving credit facility in connection with the consummation of the proposed merger with RRI Energy.

Mirant North America Senior Notes

The senior notes due in 2013 are senior unsecured obligations of Mirant North America. In addition, certain subsidiaries of Mirant North America (not including Mirant Mid-Atlantic or Mirant Energy Trading) have jointly and severally guaranteed, as senior unsecured obligations, the senior notes. The Mirant North America senior notes have no recourse to any other Mirant entities, including Mirant Americas Generation.

See Note A for a discussion of the contemplated repayment of the senior notes in connection with the consummation of the proposed merger with RRI Energy.

E. Guarantees and Letters of Credit

Mirant generally conducts its business through various operating subsidiaries which enter into contracts as a routine part of their business activities. In certain instances, the contractual obligations of such subsidiaries are guaranteed by, or otherwise supported by, Mirant or another of its subsidiaries, including by letters of credit issued under the credit facilities of Mirant North America.

In addition, Mirant and its subsidiaries enter into various contracts that include indemnification and guarantee provisions. Examples of these contracts include financing and lease arrangements, purchase and sale agreements, including for commodities, construction agreements and agreements with vendors. Although the primary obligation of Mirant or a subsidiary under such contracts is to pay money or render performance, such contracts may include obligations to indemnify the counterparty for damages arising from the breach thereof and, in certain instances, other existing or potential liabilities. In many cases, the Company s maximum potential liability cannot be estimated because some of the underlying agreements contain no limits on potential liability.

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Upon issuance or modification of a guarantee, the Company determines if the obligation is subject to initial recognition and measurement of a liability and/or disclosure of the nature and terms of the guarantee. Generally, guarantees of the performance of a third party are subject to the recognition and measurement, as well as the disclosure provisions of the accounting guidance related to guarantees. Such guarantees must initially be recorded at fair value, as determined in accordance with the accounting guidance. The Company did not have any guarantees at June 30, 2010, that met the recognition requirements of the accounting guidance.

For the six months ended June 30, 2010, Mirant had net increases to its guarantees and letters of credit of approximately $19 million, which included net increases of approximately $17 million to its letters of credit, approximately $1 million to other guarantees and approximately $1 million to its surety bonds.

This Note should be read in conjunction with the complete description under Note 7, *Commitments and Contingencies Guarantees*, to the Company s consolidated financial statements in its 2009 Annual Report on Form 10-K.

F. Pension and Other Postretirement Benefit Plans

Mirant has various defined benefit and defined contribution pension plans, and other postretirement benefit plans. For a further discussion of these plans see Note 6, *Employee Benefit Plans* in the Company s 2009 Annual Report on Form 10-K.

Net Periodic Benefit Cost (Credit)

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

	Pension Plans Three Months Ended June 30,		Other Postretirement Benefit Plans Three Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Service cost	$ 2	$ 2	$	$
Interest cost	4	4	1	1
Expected return of plan assets	(6)	(5)		
Net amortization[1]	1		(2)	(1)
Curtailments			(37)	
Net periodic benefit cost (credit)	$ 1	$ 1	$ (38)	$

	Pension Plans Six Months Ended June 30,		Other Postretirement Benefit Plans Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Service cost	$ 4	$ 4	$	$ 1
Interest cost	8	8	2	2
Expected return of plan assets	(11)	(11)		
Net amortization[1]	1	1	(4)	(3)
Curtailments			(37)	
Net periodic benefit cost (credit)	$ 2	$ 2	$ (39)	$

[1] Net amortization amount includes prior service costs and actuarial gains or losses.

Curtailment of Mid-Atlantic Other Postretirement Benefits

During the second quarter of 2010, the Company entered into a new collective bargaining agreement with its employees represented by IBEW Local 1900. The new agreement includes a change to the postretirement healthcare benefit plan covering Mid-Atlantic union employees to eliminate employer-provided healthcare subsidies through a gradual phase-out. For current employees who retire during the term of this collective bargaining agreement, the gradual phase-out will continue through 2015, at which time those retirees will be responsible for 100% of their healthcare coverage. Subsidies for employees who retired prior to June 1, 2010, will continue through December 31, 2010. The curtailment resulted in a remeasurement of the liability related to postretirement benefits for Mid-Atlantic union employees. In performing the remeasurement, the Company used an updated discount rate of 5.31% as compared to the discount rate of 5.62% used in the Company s previous measurement at December 31, 2009. The Company did not adjust any other valuation assumptions as a result of the remeasurement. The Company recorded the effects of the plan curtailment during the second quarter of 2010 and recognized a reduction in other postretirement liabilities of approximately $45 million, an increase in other comprehensive income of approximately $8 million on the unaudited condensed consolidated balance sheets as of June 30, 2010, and a gain of $37 million reflected as a reduction in operations and maintenance expense on the unaudited condensed consolidated statement of operations.

G. Stock-based Compensation

On March 11, 2010, the Company granted stock options and issued restricted stock units to executives and certain other employees under the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. The stock options have a ten-year term and the stock options and restricted stock units vest in three equal installments on each of the first, second and third anniversaries of the grant date. The stock options have an exercise price of $13.19, the Company s closing stock price on the day of the grant, and a grant date fair value of $5.64. The restricted stock units have a grant date fair value of $13.19, the Company s closing stock price on the day of the grant.

On May 12, 2010, the Company issued restricted stock units to non-management members of the Board of Directors under the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. The restricted stock units vest on the first anniversary of the grant date and delivery of the underlying shares is deferred until their directorship terminates. The restricted stock units have a grant date fair value of $12.21, the Company s closing stock price on the day of the grant.

During the three and six months ended June 30, 2010, the Company recognized approximately $4 million and $8 million, respectively, of compensation expense related to stock options and restricted stock units. During the three and six months ended June 30, 2009, the Company recognized approximately $12 million and $16 million, respectively, of compensation expense related to stock options and restricted stock units, which includes compensation expense associated with the separation of certain executives in 2009. These amounts are included in operations and maintenance expense in the unaudited condensed consolidated statements of operations.

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Stock-based compensation activity for the six months ended June 30, 2010, is as follows:

Stock Options Service-based

	Number of Options	Weighted Average Exercise Price	Aggregate Intrinsic Value[1] (in thousands)
Outstanding at January 1, 2010	4,040,576	$ 24.05	$ 5,818
Granted	951,224	$ 13.19	
Exercised or converted	(120,867)	$ 10.40	
Forfeited	(37,130)	$ 13.64	
Expired	(650,194)	$ 29.14	
Outstanding at June 30, 2010	4,183,609	$ 21.28	$ 169
Exercisable or convertible at June 30, 2010	2,354,018	$ 26.62	$ 55
Cash proceeds from exercise of options for the six months ended June 30, 2010	$ 1,257,017		

[1] Aggregate intrinsic value is calculated based on the closing stock price at June 30, 2010, of $10.56.

Restricted Stock Units Service-based

	Number of Units/ Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2010	1,587,324	$ 14.95
Granted	1,037,499	$ 13.15
Vested	(649,349)	$ 17.83
Forfeited	(32,745)	$ 12.78
Outstanding at June 30, 2010	1,942,729	$ 13.06

Change of Control

If consummated, the proposed merger with RRI Energy will constitute a change of control as defined under the Mirant Corporation 2005 Omnibus Incentive Compensation Plan. As a result, all outstanding stock options and restricted stock units will become fully vested. The outstanding stock options will be converted into options to purchase RRI Energy common stock and restricted stock units will be converted into shares of RRI Energy based on the Exchange Ratio and the terms of the Merger Agreement. Upon the closing of the merger, RRI Energy will be renamed GenOn Energy. In addition, any unrecognized compensation expense associated with previously unvested stock options and restricted stock units will be immediately recognized as compensation expense. As of June 30, 2010, there was approximately $32 million of total unrecognized compensation cost, excluding estimated forfeitures, related to non-vested stock-based awards.

H. Earnings (Loss) Per Share

Mirant calculates 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. As a result of the net loss for the three months ended June 30, 2010, diluted EPS was computed in the same manner as basic EPS in accordance with accounting guidance.

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The following table shows the computation of basic and diluted EPS for the three and six months ended June 30, 2010 and 2009 (in millions except per share data):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net income (loss)	$ (263)	$ 163	$ 144	$ 543
Basic and diluted:				
Weighted average shares outstanding basic	145	145	145	145
Shares from assumed vesting of restricted stock units			1	
Weighted average shares outstanding diluted	145	145	146	145
Basic and Diluted EPS				
Basic EPS	$ (1.81)	$ 1.12	$ 0.99	$ 3.74
Diluted EPS	$ (1.81)	$ 1.12	$ 0.99	$ 3.74

For the three and six months ended June 30, 2010 and 2009, the weighted average number of securities that could potentially dilute basic EPS in the future that were not included in the computation of diluted EPS because to do so would have been antidilutive were as follows:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(shares in millions)			
Series A Warrants	27	27	27	27
Series B Warrants	7	7	7	7
Restricted stock units	1		1	1
Stock options	5	5	4	4
Total number of antidilutive shares	40	39	39	39

Change of Control Series A Warrants and Series B Warrants

If the proposed merger with RRI Energy is consummated, the holders of the Series A Warrants and Series B Warrants will have the right to acquire and receive, upon the exercise of such warrants, the number of shares of RRI Energy common stock that would have been issued or paid to the holders of the Series A Warrants and Series B Warrants if such holders were to have exercised the Series A Warrants and Series B Warrants immediately prior to the closing of the merger. Upon the closing of the merger, RRI Energy will be renamed GenOn Energy. The obligations in respect of the outstanding Series A Warrants and Series B Warrants, which expire on January 3, 2011, will be assumed by GenOn Energy upon consummation of the proposed merger.

I. Stockholders Equity

Stockholder Rights Plan

On March 26, 2009, Mirant announced the adoption of a stockholder rights plan (the Stockholder Rights Plan) to help protect the Company s use of its federal NOLs from certain restrictions contained in §382 of the Internal Revenue Code of 1986, as amended. In general, an ownership change would occur if certain shifts in ownership of the Company s stock exceed 50 percentage points measured over a specified period of time. Given §382 s broad definition, an

ownership change could be the unintended consequence of otherwise normal market trading in the Company s stock that is outside the Company s control. The Stockholder Rights Plan was adopted to reduce the likelihood of such an unintended ownership change occurring. However, there can be no assurance that the Stockholder Rights Plan will prevent such an ownership change.

Under the Stockholder Rights Plan, when a person or group has obtained beneficial ownership of 4.9% or more of the Company s common stock, or an existing holder with greater than 4.9% ownership acquires more shares representing at least an additional 0.2% of the Company s common stock, there would be a triggering event causing potential significant dilution in the economic interest and voting power of such person or group. Such triggering event would also occur if an existing holder with greater than 4.9% ownership but less than 5.0% ownership acquires more shares that would result in such stockholder obtaining beneficial ownership of 5.0% or more of the Company s common stock. The Board of Directors has the discretion to exempt an acquisition of common stock from the provisions of the Stockholder Rights Plan if it determines the acquisition will not jeopardize tax benefits or is otherwise in the Company s best interests.

On February 26, 2010, Mirant announced that the Board of Directors had extended the Stockholder Rights Plan and on April 28, 2010, the Company entered into a further amendment to the Stockholders Rights Plan (the Second Amendment) with Mellon Investor Services LLC, as Rights Agent (the Rights Agent). The Second Amendment reduces the maximum term of the Stockholders Rights Plan from ten years to three years. Under the terms of the Stockholder Rights Plan (prior to the Second Amendment), the rights (as defined in the Stockholder Rights Plan) would have expired on the earliest of (i) February 25, 2020 (the Fixed Date), (ii) the time at which the rights are redeemed, (iii) the time at which the rights are exchanged, (iv) the repeal of §382 or any successor statute, or any other change, if the Board of Directors determines that the Stockholder Rights Plan is no longer necessary for the preservation of tax benefits, (v) the beginning of a taxable year of the Company for which the Board of Directors determines that no tax benefits may be carried forward and no built-in losses may be recognized, (vi) February 25, 2011 if stockholder approval has not been obtained, or (vii) a determination by the Board of Directors, prior to the time any person or group becomes an Acquiring Person (as defined in the Stockholder Rights Plan), that the Stockholder Rights Plan and the rights are no longer in the best interests of the Company and its stockholders. The Second Amendment amends the Fixed Date to February 25, 2013. On May 6, 2010, the Company s stockholders approved the Stockholder Rights Plan at the Company s 2010 Annual Meeting of Stockholders.

Provided neither has experienced an ownership change between December 31, 2009, and the closing date of the merger, each of Mirant and RRI Energy is expected separately to experience an ownership change, as defined in §382 of the Internal Revenue Code of 1986, on the merger date as a consequence of the merger. See Note A for further information on the proposed merger and the effect on the NOLs.

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J. Segment Reporting

The Company has four operating segments: Mid-Atlantic, Northeast, California and Other Operations. The Mid-Atlantic segment consists of four generating facilities located in Maryland and Virginia with total net generating capacity of 5,194 MW. The Northeast segment consists of three generating facilities located in Massachusetts and one generating facility located in New York with total net generating capacity of 2,535 MW. The California segment consists of three generating facilities located in or near the City of San Francisco, with total net generating capacity of 2,347 MW. The California segment also includes business development efforts for new generation including Mirant Marsh Landing. Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest expense on debt at Mirant Americas Generation and Mirant North America and interest income on the Company s invested cash balances. In the following tables, eliminations are primarily related to intercompany sales of emissions allowances and interest on intercompany notes receivable and notes payable.

Operating Segments

	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
			(in millions)			
Three Months Ended June 30, 2010:						
Operating revenues[1]	$ 170	$ 40	$ 33	$ 1	$	$ 244
Cost of fuel, electricity and other products[2]	250	18	4			272
Gross margin	(80)	22	29	1		(28)
Operating Expenses:						
Operations and maintenance	117	27	18	(30)		132
Depreciation and amortization	36	6	7	4		53
Gain on sales of assets, net	(1)					(1)
Total operating expenses (income), net	152	33	25	(26)		184
Operating income (loss)	(232)	(11)	4	27		(212)
Total other expense, net	1	1		48		50
Income (loss) before income taxes	(233)	(12)	4	(21)		(262)
Provision for income taxes				1		1
Net income (loss)	$ (233)	$ (12)	$ 4	$ (22)	$	$ (263)
Total assets at June 30, 2010	$ 5,954	$ 597	$ 125	$ 5,453	$ (2,283)	$ 9,846

[1] Includes unrealized losses of $205 million, $13 million and $13 million for Mid-Atlantic, Northeast and Other Operations, respectively.
[2] Includes unrealized losses of $112 million for Mid-Atlantic and unrealized gains of $3 million for Northeast.

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	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
			(in millions)			
Six Months Ended June 30, 2010:						
Operating revenues[1]	$ 909	$ 112	$ 71	$ 32	$	$ 1,124
Cost of fuel, electricity and other products[2]	405	62	12			479
Gross margin	504	50	59	32		645
Operating Expenses:						
Operations and maintenance	230	51	38	(21)		298
Depreciation and amortization	69	12	15	8		104
Gain on sales of assets, net	(3)					(3)
Total operating expenses (income), net	296	63	53	(13)		399
Operating income (loss)	208	(13)	6	45		246
Total other expense, net	2	1		98		101
Income (loss) before income taxes	206	(14)	6	(53)		145
Provision for income taxes				1		1
Net income (loss)	$ 206	$ (14)	$ 6	$ (54)	$	$ 144
Total assets at June 30, 2010	$ 5,954	$ 597	$ 125	$ 5,453	$ (2,283)	$ 9,846

[1] Includes unrealized gains of $133 million and $2 million for Mid-Atlantic and Northeast, respectively, and unrealized losses of $3 million for Other Operations
[2] Includes unrealized losses of $104 million and $16 million for Mid-Atlantic and Northeast, respectively.

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	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
			(in millions)			
Three Months Ended June 30, 2009:						
Operating revenues[1]	$ 391	$ 58	$ 33	$ 14	$	$ 496
Cost of fuel, electricity and other products[2]	134	13	4	(1)		150
Gross margin	257	45	29	15		346
Operating Expenses:						
Operations and maintenance	101	35	24	(46)		114
Depreciation and amortization	24	5	5	2		36
Gain on sales of assets, net	(2)					(2)
Total operating expenses (income), net	123	40	29	(44)		148
Operating income	134	5		59		198
Total other expense, net	1			34		35
Income before income taxes	133	5		25		163
Provision for income taxes						
Net income	$ 133	$ 5	$	$ 25	$	$ 163
Total assets at December 31, 2009	$ 5,807	$ 616	$ 144	$ 5,239	$ (2,278)	$ 9,528

[1] Includes unrealized losses of $4 million, $6 million and $34 million for Mid-Atlantic, Northeast and Other Operations, respectively.
[2] Includes unrealized gains of $4 million and $26 million for Mid-Atlantic and Northeast, respectively.

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	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
			(in millions)			
Six Months Ended June 30, 2009:						
Operating revenues[1]	$ 1,063	$ 210	$ 68	$ 36	$ (3)	$ 1,374
Cost of fuel, electricity and other products[2]	299	101	12	9		421
Gross margin	764	109	56	27	(3)	953
Operating Expenses:						
Operations and maintenance	206	67	43	(40)		276
Depreciation and amortization	48	9	10	5		72
Gain on sales of assets, net	(10)	(2)	(1)		(4)	(17)
Total operating expenses (income), net	244	74	52	(35)	(4)	331
Operating income	520	35	4	62	1	622
Total other expense, net	2		1	68		71
Income (loss) before income taxes	518	35	3	(6)	1	551
Provision for income taxes				8		8
Net income (loss)	$ 518	$ 35	$ 3	$ (14)	$ 1	$ 543
Total assets at December 31, 2009	$ 5,807	$ 616	$ 144	$ 5,239	$ (2,278)	$ 9,528

[1] Includes unrealized gains of $238 million and $22 million for Mid-Atlantic and Northeast, respectively, and unrealized losses of $49 million for Other Operations.

[2] Includes unrealized gains of $5 million and $24 million for Mid-Atlantic and Northeast, respectively.

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K. Litigation and Other Contingencies

The Company is involved in a number of significant legal proceedings. In certain cases, plaintiffs seek to recover large and sometimes unspecified damages, and some matters may be unresolved for several years. The Company cannot currently determine the outcome of the proceedings described below or the ultimate amount of potential losses and therefore has not made any provision for such matters unless specifically noted below. Pursuant to guidance related to accounting for contingencies, management provides for estimated losses to the extent information becomes available indicating that losses are probable and that the amounts are reasonably estimable. Additional losses could have a material adverse effect on the Company s results of operations, financial position or cash flows.

Stockholder Litigation

Mirant and its directors have been named as defendants in four putative stockholder class actions filed in the Superior Court of Fulton County, Georgia, in connection with the merger of Mirant and RRI Energy: *Rosenbloom* v. *Cason, et al*., No. 2010CV184223, filed April 13, 2010; *The Vladmir Gusinsky Living Trust* v. *Muller*, *et al.*, No, 2010CV184331, filed April 15, 2010; *Ng v. Muller, et al*., No. 2010CV184449, filed April 16, 2010; and *Bayne v. Muller, et al.*, No. 2010CV184648, filed April 21, 2010. The plaintiffs seek to enjoin the merger, alleging that Mirant s directors breached their fiduciary duties by failing to maximize the value to be received by Mirant stockholders, by agreeing to certain deal protection measures, and by improperly considering certain directors personal interests in the transaction, such as future employment by the post-merger entity, in determining whether to enter into the Merger Agreement. Three of the complaints assert a claim of aiding and abetting breach of fiduciary duty against Mirant and RRI Energy; the fourth, Bayne, asserts this claim against RRI Energy alone. In three of the four actions, the plaintiffs have amended their complaints to add allegations that the defendants breached their fiduciary duties by failing to disclose certain information in the preliminary joint proxy statement/prospectus included in the Form S-4 Registration Statement related to the merger that RRI Energy filed on May 28, 2010, and amended on July 6, 2010. In addition to an order enjoining the transaction, the plaintiffs variously seek, among other things: additional disclosures regarding the merger; an accounting to plaintiffs or imposition of a constructive trust in favor of plaintiffs for all damages allegedly caused by defendants and for all profits and any special benefits obtained as a result of defendants purported breaches of fiduciary duties; rescission of the merger, if consummated, or an award to plaintiff of recessionary damages; and attorneys fees and expenses. Mirant and its directors have filed motions to dismiss each of the four amended complaints in their entirety for failure to state a claim. Mirant and its directors view the complaints to be without merit and intend to defend against them vigorously.

Scrubber Contract Issues

Mirant Mid-Atlantic is working through various issues with Stone & Webster, Inc. (Stone & Webster), the EPC contractor for the scrubber projects at the Chalk Point, Dickerson and Morgantown generating facilities to determine the final amount owed to Stone & Webster. Stone & Webster is estimating that the cost incurred under the EPC contract at completion will exceed the amount currently budgeted. If the costs actually incurred for the EPC work were to equal the amount projected by Stone & Webster, the costs incurred by Mirant Mid-Atlantic and Mirant Chalk Point for environmental controls to meet the Maryland Healthy Air Act would exceed the $1.674 billion currently budgeted for the total project by approximately 4%. Mirant Mid-Atlantic is questioning various costs incurred by Stone & Webster and is auditing various components of the costs incurred by Stone & Webster. Mirant Mid-Atlantic also has submitted owner change orders to Stone & Webster that would reduce the costs incurred under the EPC contract by removing work included in the contract specifications that ultimately was not performed or that was completed by Mirant Mid-Atlantic. Mirant Mid-Atlantic expects the final contract amount to be less than the amount projected by Stone & Webster, but cannot predict how much of a reduction will be achieved. The current budget of $1.674 billion continues to represent management s best estimate of the Company s total capital expenditures for compliance with the Maryland Healthy Air Act.

Environmental Matters

Brandywine Fly Ash Facility. By letter dated November 19, 2009, the Defenders of Wildlife, Sierra Club, Patuxent Riverkeeper and Chesapeake Climate Action Network (the Brandywine Noticing Parties) notified Mirant, Mirant Mid-Atlantic and Mirant MD Ash Management of their intent to file suit for violations of the Clean Water Act and Maryland s Water Pollution Control Law alleged to have occurred at the Brandywine Fly Ash Facility owned by Mirant MD Ash Management in Prince George s County, Maryland. They contend that the operation of the Brandywine facility has resulted in unpermitted discharges of certain pollutants, including aluminum, arsenic, cadmium, copper, lead, mercury, selenium and zinc, through three outfalls and through seepage to the ground water from the disposal cells at the facility. They also assert that the discharges cause violations of certain of Maryland s water quality criteria. Finally, the Brandywine Noticing Parties contend that Mirant MD Ash Management failed to perform certain monitoring and sampling or to file certain reports required under its existing National Pollutant Discharge Elimination System (NPDES) permit for the Brandywine Fly Ash Facility. The notice states that the Brandywine Noticing Parties will request the court to enjoin further violations, to impose civil penalties under the Clean Water Act of up to $37,500 per day per violation for the period after January 4, 2006, and to award them attorney s fees. By letter dated January 15, 2010, the MDE advised Mirant Mid-Atlantic and Mirant MD Ash Management of its intent to file suit for violations of the Clean Water Act and Maryland s Water Pollution Control Law based upon factual allegations similar to those asserted by the Brandywine Noticing Parties. Mirant disputes the allegations of violations of the Clean Water Act and Maryland s Water Pollution Control Law made by the Brandywine Noticing Parties in the November 19, 2009, letter and by MDE in its letter of January 15, 2010.

On April 2, 2010, the MDE filed a complaint against Mirant Mid-Atlantic and Mirant MD Ash Management in the United States District Court for the District of Maryland asserting violations of the Clean Water Act and Maryland s Water Pollution Control Law on the grounds alleged in the November 19, 2009, letter from the Brandywine Noticing Parties and the MDE s letter of January 15, 2010. Four environmental advocacy groups have filed a motion seeking to intervene as plaintiffs in the proceeding. Mirant MD Ash Management and Mirant Mid-Atlantic have filed a motion seeking dismissal of the complaint on various grounds, including that the complaint fails to state a claim under the Clean Water Act because the discharges alleged were within the scope of possible discharges identified in filings made by Mirant MD Ash Management with the MDE to obtain its existing NPDES permit for the Brandywine Fly Ash Facility.

EPA Information Request. In January 2001, the EPA issued a request for information to Mirant concerning the implications under the EPA s NSR regulations promulgated under the Clean Air Act of past repair and maintenance activities at the Potomac River generating facility in Virginia and the Chalk Point, Dickerson and Morgantown generating facilities in Maryland. The requested information concerned the period of operations that predates the ownership and lease of those facilities by Mirant Potomac River, Mirant Chalk Point and Mirant Mid-Atlantic. Mirant responded fully to this request. Under the APSA, Pepco is responsible for fines and penalties arising from any violation of the NSR regulations associated with operations prior to the

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acquisition or lease of the facilities by Mirant Potomac River, Mirant Chalk Point and Mirant Mid-Atlantic. If a violation is determined to have occurred at any of the facilities, Mirant Potomac River, Mirant Chalk Point and Mirant Mid-Atlantic, as the owner or lessee of the facility, may be responsible for the cost of purchasing and installing emissions control equipment, the cost of which may be material. Mirant Chalk Point and Mirant Mid-Atlantic have installed a variety of emissions control equipment on the Chalk Point, Dickerson and Morgantown generating facilities in Maryland to comply with the Maryland Healthy Air Act, but that equipment may not include all of the emissions control equipment that could be required if a violation of the EPA s NSR regulations is determined to have occurred at one or more of those facilities. If such a violation is determined to have occurred after the acquisition or lease of the facilities by Mirant Potomac River, Mirant Chalk Point and Mirant Mid-Atlantic or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, Mirant Potomac River, Mirant Chalk Point or Mirant Mid-Atlantic could also be subject to fines and penalties by the state or federal government for the period after its acquisition or lease of the facility at issue, the cost of which may be material, although applicable bankruptcy law may bar such liability for periods prior to January 3, 2006, when the Plan became effective for Mirant Potomac River, Mirant Chalk Point and Mirant Mid-Atlantic.

Faulkner Fly Ash Facility. By letter dated April 2, 2008, the Environmental Integrity Project and the Potomac Riverkeeper notified Mirant and various of its subsidiaries that they and certain individuals intended to file suit alleging that violations of the Clean Water Act were occurring at the Faulkner Fly Ash Facility owned by Mirant MD Ash Management. The April 2, 2008, letter alleged that the Faulkner facility discharged certain pollutants at levels that exceed Maryland s water quality criteria, that it discharged certain pollutants without obtaining an appropriate NPDES permit, and that Mirant MD Ash Management failed to perform monthly monitoring required under an applicable NPDES permit. The letter indicated that the organizations intended to file suit to enjoin the violations alleged, to obtain civil penalties for past violations occurring after January 3, 2006, and to recover attorneys fees. Mirant disputes the allegations of violations of the Clean Water Act made by the two organizations in the April 2, 2008, letter.

In May 2008, the MDE filed a complaint in the Circuit Court for Charles County, Maryland, against Mirant MD Ash Management and Mirant Mid-Atlantic. The complaint alleges violations of Maryland s water pollution laws similar to those asserted in the April 2, 2008, letter from the Environmental Integrity Project and the Potomac Riverkeeper. The MDE complaint requests that the court (1) prohibit continuation of the alleged unpermitted discharges, (2) require Mirant MD Ash Management and Mirant Mid-Atlantic to cease from disposing of any further coal combustion byproducts at the Faulkner Fly Ash Facility and close and cap the existing disposal cells within one year and (3) assess civil penalties of up to $10,000 per day for each violation. The discharges that are the subject of the MDE s complaint result from a leachate treatment system installed by Mirant MD Ash Management in accordance with a December 18, 2000, Complaint and Consent Order (the December 2000 Consent Order) entered by the Maryland Secretary of the Environment, Water Management Administration pursuant to an agreement between the MDE and Pepco, the previous owner of the Faulkner Fly Ash Facility. Mirant MD Ash Management and Mirant Mid-Atlantic on July 23, 2008, filed a motion seeking dismissal of the MDE complaint, arguing that the discharges are permitted by the December 2000 Consent Order. In September 2009, the court denied a motion by Environmental Integrity Project seeking to intervene as a party to the suit, and the Environmental Integrity Project has appealed that ruling.

Suit Regarding Chalk Point Emissions. On June 25, 2009, the Chesapeake Climate Action Network and four individuals filed a complaint against Mirant Mid-Atlantic and Mirant Chalk Point in the United States District Court for the District of Maryland. The plaintiffs allege that Mirant Chalk Point has violated the Clean Air Act and Maryland environmental regulations by failing to install controls to limit emissions of particulate matter on unit 3 and unit 4 of the Chalk Point generating facility, which at times burn residual fuel oil. The plaintiffs seek to enjoin the alleged violations, to obtain civil penalties of up to $32,500 per day for past noncompliance and to recover attorneys fees. Mirant Mid-Atlantic and Mirant Chalk Point dispute the plaintiffs allegations of violations of the Clean Air Act and Maryland environmental regulations. On October 13, 2009, Mirant Mid-Atlantic and Mirant Chalk Point filed a motion seeking dismissal of the complaint on the grounds that it was barred (1) under principles of res judicata by the dismissal with prejudice in January 2007 of similar claims filed by environmental advocacy organizations asserting that emissions from Chalk Point units 3 and 4 violated the Clean Air Act and (2) by actions taken by the MDE currently and over a number of years to ensure compliance by Chalk Point units 3 and 4 with regulations under the Clean Air Act and Maryland law limiting emissions of particulate matter.

Mirant Mid-Atlantic and Mirant Chalk Point 2008 Consent Decree. In March 2008, Mirant Mid-Atlantic, Mirant Chalk Point and the MDE entered into a consent decree that provided stipulated penalties for various future violations of Maryland regulations related to emissions from the Chalk Point, Dickerson and Morgantown generating facilities. That consent decree provided in part that if emissions from the stacks for Morgantown units 1 and 2, the common stack for Chalk Point units 1 and 2, or the common stack for Dickerson units 1, 2 and 3 failed to achieve compliance with certain opacity limits in the period July 1, 2009 through December 31, 2009, a stipulated penalty would apply of $1,000 per day of violation. In February 2010, the MDE notified Mirant Mid-Atlantic that it was seeking payment of a stipulated penalty of $134,000 for failures to comply with these opacity limits during the third quarter of 2009. In April 2010, the MDE notified Mirant Mid-Atlantic and Mirant Chalk Point that it was seeking payment of a stipulated penalty of $91,000 for exceedances of the opacity limits in the fourth quarter of 2009. Mirant Mid-Atlantic has paid the stipulated penalties.

Mirant Mid-Atlantic NOV Regarding Reporting of Ozone Season NOx Emissions. In March 2010, the MDE issued an NOV to Mirant Mid-Atlantic asserting that it had failed in 2009 to comply with state regulations requiring it to notify MDE when the Chalk Point, Dickerson and Morgantown generating facilities had exceeded 80% of the applicable limitation on ozone season NOx emissions. The NOV states that such a violation can result in a civil penalty of up to $25,000 for each day of violation.

Mirant Potomac River NOV Regarding Particulate Matter Continuous Emissions Monitoring System. By letter dated April 6, 2010, the Virginia DEQ issued an NOV to Mirant Potomac River asserting that it had failed to include required particulate matter continuous emissions monitoring system (PM CEMS) data in compliance reports submitted for the second half and fourth quarter of 2009. The NOV alleges that when the PM CEMS data were subsequently provided, they indicated that particulate matter emissions may have occurred above the permitted limit. Mirant Potomac River thinks that the PM CEMS equipment was not functioning properly and that the data indicating exceedances of the emissions limit for particulate matter are erroneous. The NOV states that such violations can result in various civil penalties, including a civil penalty of up to $32,500 per day for each violation.

Mirant Potomac River NOV Regarding Opacity Excursions. By letter dated May 12, 2010, the Virginia DEQ issued an NOV to Mirant Potomac River asserting that in four six-minute intervals in February 2010 the opacity readings from one of the stacks at the Potomac River generating facility exceeded the applicable limit. On July 8, 2010, the Virginia DEQ issued another NOV to Mirant Potomac River asserting that on June 21, 2010, the Potomac River generating facility exceeded its permitted opacity limits for three six-minute intervals. The NOVs state that such violations can result in various civil penalties, including a civil penalty of up to $32,500 per day for each violation.

Mirant Mid-Atlantic, Mirant Chalk Point and Mirant Potomac River Amended NOx Consent Decree. In 2006, Mirant Mid-Atlantic, Mirant Chalk Point, Mirant Potomac River, the MDE, the Virginia DEQ, the EPA and the United States Department of Justice (DOJ) signed a consent decree that was entered by the court in 2007 to address alleged NOx exceedances from Mirant Potomac River in 2003. Among other things, the consent decree provided more stringent NOx emission limits for the Morgantown units and various reporting requirements along with stipulated penalties for future violations. In April 2010, the DOJ notified Mirant Mid-Atlantic that it was seeking a stipulated penalty of $168,000 based upon unit 2 of the Morgantown generating facility exceeding the 30-day rolling average emission rate limit specified by the consent decree on 16 days in November 2009, the failure to provide a written report of those exceedances within ten days and the late submission of NOx data for the fourth quarter of 2008. The DOJ subsequently reduced the stipulated penalty to $163,000, and Mirant Mid-Atlantic has paid that amount.

Montgomery County Carbon Emissions Levy. Mirant Mid-Atlantic s Dickerson generating facility is located in Montgomery County, Maryland. The Montgomery County Council enacted a law (the CO2 Levy) effective May 29, 2010, that imposes a levy on major emitters of CO2 in Montgomery County of $5 per ton of CO2 emitted. The CO2 Levy defines a major emitter of CO2 in Montgomery County to be a source emitting 1 million tons or more annually of CO2. Based upon historical emissions, the Dickerson generating facility is expected to fall within the definition of a major emitter, and is currently the only facility in Montgomery County that would meet the criteria to be a major emitter. Mirant estimates that the CO2 Levy will impose an additional $10 million to $15 million per year in levies owed to Montgomery County. On June 1, 2010, Mirant Mid-Atlantic filed an action against Montgomery County in the United States District Court for the District of Maryland seeking a determination that the CO2 Levy is unlawful. In its complaint, Mirant Mid-Atlantic contends that the CO2 Levy violates its equal protection and due process rights, imposes an unconstitutional excessive fine, is an unconstitutional bill of attainder, constitutes a prohibited special law under the Maryland Constitution, and is preempted by Maryland law and the RGGI, an interstate compact to which Maryland is a party. Montgomery County filed a motion to dismiss, arguing that the CO2 Levy is a tax and that the district court lacks the jurisdiction to hear challenges to such a tax under the federal Tax Injunction Act. On July 12, 2010, the district court ruled that the CO2 Levy is a tax rather than a fee as argued by Mirant Mid-Atlantic, and it dismissed the suit for lack of jurisdiction. Mirant Mid-Atlantic has appealed that ruling to the United States Court of Appeals for the Fourth Circuit. If the district court s ruling is not reversed on appeal, Mirant Mid-Atlantic intends to refile its legal challenges to the CO2 Levy in the Maryland state courts.

Riverkeeper Suit Against Mirant Lovett. On March 11, 2005, Riverkeeper, Inc. filed suit against Mirant Lovett in the United States District Court for the Southern District of New York under the Clean Water Act. The suit alleges that Mirant Lovett failed to implement a marine life exclusion system at its former Lovett generating facility and to perform monitoring for the exclusion of certain aquatic organisms from the facility s cooling water intake structures in violation of Mirant Lovett s water discharge permit issued by the State of New York. The plaintiff requested the court to impose civil penalties of $32,500 per day of violation and to award the plaintiff attorneys fees. Mirant Lovett s view is that it complied with the terms of its water discharge permit, as amended by a Consent Order entered June 29, 2004. Mirant Lovett filed a motion seeking dismissal of the suit on the grounds that it complied with the terms of its water discharge permit, the closure of the Lovett generating facility in April 2008 moots the plaintiff s request for injunctive relief, and the discharge in bankruptcy received by Mirant Lovett in 2007 bars any claim for penalties. On December 15, 2009, the district court granted in part and denied in part Mirant Lovett s motion to dismiss. The court dismissed the plaintiff s claims for injunctive relief and for penalties for any period prior to Mirant Lovett s emergence from bankruptcy on October 2, 2007. It allowed to go forward claims alleging that Mirant Lovett violated its water discharge permit by not implementing the marine life exclusion system between the later of February 23, 2008 or when ice conditions on the Hudson River allowed for the system s safe deployment and April 19, 2008, when the Lovett generating facility ceased operation, concluding that the June 29, 2004 Consent Order did not have the effect of modifying the water discharge permit.

Chapter 11 Proceedings

On July 14, 2003, and various dates thereafter, Mirant Corporation and certain of its subsidiaries (collectively, the Mirant Debtors) filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. Mirant and most of the Mirant Debtors emerged from bankruptcy on January 3, 2006, when the Plan became effective. The remaining Mirant Debtors (Mirant New York, Mirant Bowline, Mirant Lovett, Mirant NY-Gen and Hudson Valley Gas) emerged from bankruptcy on various dates in 2007. As of June 30, 2010, approximately 837,000 of the shares of Mirant common stock to be distributed under the Plan had not yet been distributed and have been reserved for distribution with respect to claims disputed by the Mirant Debtors that have not been resolved. Under the terms of the Plan, upon the resolution of such a disputed claim, the claimant will receive the same pro rata distributions of Mirant common stock, cash, or both common stock and cash as previously allowed claims, regardless of the price at which Mirant common stock is trading at the time the claim is resolved.

To the extent the aggregate amount of the payouts determined to be due with respect to disputed claims ultimately exceeds the amount of the funded claim reserve, Mirant would have to issue additional shares of common stock to address the shortfall, which would dilute existing Mirant stockholders, and Mirant and Mirant Americas Generation would have to pay additional cash amounts as necessary under the terms of the Plan to satisfy such pre-petition claims. If Mirant is required to issue additional shares of common stock to satisfy unresolved claims, certain parties who received approximately 21 million of the 300 million shares of common stock distributed under the Plan are entitled to receive additional shares of common stock to avoid dilution of their distributions under the Plan.

Actions Pursued by MC Asset Recovery

Under the Plan, the rights to certain actions filed by Mirant and various of its subsidiaries against third parties were transferred to MC Asset Recovery. MC Asset Recovery, although wholly-owned by Mirant, is governed by managers who are independent of Mirant and its other subsidiaries. Under the Plan, any cash recoveries obtained by MC Asset Recovery from the actions transferred to it, net of fees and costs incurred in prosecuting the actions, are to be paid to the unsecured creditors of Mirant Corporation in the Chapter 11 proceedings and the holders of the equity interests in Mirant 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 Mirant is responsible for income taxes related to its operations. The Plan provides that Mirant may not reduce payments to be made to unsecured creditors and former holders of equity interests from recoveries obtained by MC Asset Recovery for the taxes owed by Mirant, if any, on any net recoveries up to $175 million. If the aggregate recoveries exceed $175 million net of costs, then under the Plan Mirant may

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reduce the payments to be made to such unsecured creditors and former holders of equity interests 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 MC Asset Recovery s Limited Liability Company Agreement also obligated Mirant to make contributions to MC Asset Recovery as necessary to pay professional fees and certain other costs reasonably incurred by MC Asset Recovery, including expert witness fees and other costs of the actions transferred to MC Asset Recovery. In June 2008, Mirant and MC Asset Recovery, with the approval of the Bankruptcy Court, agreed to limit the total amount of funding to be provided by Mirant to MC Asset Recovery to $67.8 million, and the amount of such funding obligation not already incurred by Mirant at that time was fully accrued. Mirant 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 Mirant Corporation and the former holders of equity interests.

On March 31, 2009, The Southern Company (Southern Company) and MC Asset Recovery entered into a settlement agreement (the MCAR Settlement) resolving claims asserted by MC Asset Recovery in MC Asset Recovery, LLC v. Southern Company, a suit that was pending in the Northern District of Georgia (the Southern Company Litigation). Southern Company filed a Form 8-K dated April 2, 2009, that described the settlement and the claims that it resolved. Southern Company and MC Asset Recovery finalized certain terms of the settlement on June 8, 2009. Pursuant to the settlement, 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 Mirant, 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 Mirant. In accordance with the Plan, Mirant 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. The Company recognized the $52 million as a reduction of operations and maintenance expense for the year ended December 31, 2009. Pursuant to MC Asset Recovery s Limited Liability Company Agreement and an order of the Bankruptcy Court dated October 31, 2006, Mirant distributed approximately $1.7 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, Mirant has no further obligation to provide funding to MC Asset Recovery. As a result, Mirant reversed its remaining accrual of $10 million of funding obligations as a reduction in operations and maintenance expense for the year ended December 31, 2009. The Company does not expect to owe any taxes related to the MC Asset Recovery settlement with Southern Company. MC Asset Recovery had $37 million and $39 million of assets included in funds on deposit and liabilities included in accounts payable and accrued liabilities in its unconsolidated balance sheets at June 30, 2010 and December 31, 2009, respectively.

One of the two remaining actions transferred to MC Asset Recovery seeks to recover damages for fraudulent transfers that occurred prior to the filing of Mirant s bankruptcy proceedings. That action alleges that the defendants engaged in transactions with Mirant at a time when it was insolvent or was rendered insolvent by the resulting transfers and that it did not receive fair value for those transfers. If MC Asset Recovery succeeds in obtaining any recoveries on these avoidance claims transferred to it, the party or parties from which such recoveries are obtained could seek to file claims in Mirant s bankruptcy proceedings. Mirant would vigorously contest the allowance of any such claims on the ground that, among other things, the recovery of such amounts 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 party receiving the claim would be entitled to either Mirant common stock or such stock and cash as provided under the Plan. Under such circumstances, the order entered by the Bankruptcy Court on December 9, 2005, confirming the Plan provides that Mirant would retain from the net amount recovered 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.

California and Western Power Markets

FERC Refund Proceedings Arising Out of California Energy Crisis. High prices experienced in California and western wholesale electricity markets in 2000 and 2001 caused various purchasers of electricity in those markets to initiate proceedings seeking refunds. Several of those proceedings remain pending either before the FERC or on appeal to the United States Court of Appeals for the Ninth Circuit (the Ninth Circuit). The proceedings that remain pending include proceedings (1) ordered by the FERC on July 25, 2001, (the FERC Refund Proceedings) to determine the amount of any refunds and amounts owed for sales made by market participants, including Mirant Americas Energy Marketing, in the CAISO or the Cal PX markets from October 2, 2000, through June 20, 2001 (the Refund Period), (2) ordered by the FERC to determine whether there had been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest from December 25, 2000, through June 20, 2001 (the Pacific Northwest Proceeding), and (3) arising from a complaint filed in 2002 by the California Attorney General that sought refunds for transactions conducted in markets administered by the CAISO and the Cal PX outside the Refund Period set by the FERC and for transactions between the DWR and various owners of generation and power marketers, including Mirant Americas Energy Marketing and subsidiaries of Mirant Americas Generation. Various parties appealed the FERC orders related to these proceedings to the Ninth Circuit seeking review of a number of issues, including changing the Refund Period to include periods prior to October 2, 2000, and expanding the sales of electricity subject to potential refund to include bilateral sales made to the DWR and other parties. Although various of these appeals remain pending, the Ninth Circuit ruled in orders issued on August 2, 2006, and September 9, 2004, that the FERC should consider further whether to grant relief for sales of electricity made in the CAISO and Cal PX markets prior to October 2, 2000, at rates found to be unjust, and, in the proceeding initiated by the California Attorney General, what remedies, including potential refunds, are appropriate where entities, including Mirant Americas Energy Marketing, purportedly did not comply with certain filing requirements for transactions conducted under market-based rate tariffs.

On January 14, 2005, Mirant and certain of its subsidiaries (the Mirant Settling Parties) entered into a Settlement and Release of Claims Agreement (the California Settlement) with PG&E, Southern California Edison Company, San Diego Gas and Electric Company, the CPUC, the DWR, the EOB and the Attorney General of the State of California (collectively, the California Parties). The California Settlement was approved by the FERC on April 13, 2005, and became effective on April 15, 2005, upon its approval by the Bankruptcy Court. The California Settlement resulted in the release of most of Mirant Americas Energy Marketing s potential liability (1) in the FERC Refund Proceedings for sales made in the CAISO or the Cal PX markets, (2) in the Pacific Northwest Proceeding, and (3) in any proceedings at the FERC resulting from the complaint filed in 2002 by the California Attorney General. Based on the California Settlement, on April 15, 2008, the FERC dismissed Mirant Americas Energy Marketing and the other subsidiaries of the Company from the proceeding initiated by the complaint filed in 2002 by the California Attorney General.

Under the California Settlement, the California Parties and those other market participants who have opted into the settlement have released the Mirant Settling Parties, including Mirant

Americas Energy Marketing, from any liability for refunds related to sales of electricity and natural gas in the western markets from January 1, 1998, through July 14, 2003. Also, the California Parties have assumed the obligation of Mirant Americas Energy Marketing to pay any refunds determined by the FERC to be owed by Mirant Americas Energy Marketing to other parties that do not opt into the settlement for transactions in the CAISO and Cal PX markets during the Refund Period, with the liability of the California Parties for such refund obligation limited to the amount of certain receivables assigned by Mirant Americas Energy Marketing to the California Parties under the California Settlement. The settlement did not relieve Mirant Americas Energy Marketing of liability for any refunds that the FERC determines it to owe (1) to participants in the Cal PX and CAISO markets that did not opt into the settlement for periods outside the Refund Period and (2) to participants in bilateral transactions with Mirant Americas Energy Marketing that did not opt into the settlement.

Resolution of the refund proceedings that remain pending before the FERC or that currently are on appeal to the Ninth Circuit could ultimately result in the FERC concluding that the prices received by Mirant Americas Energy Marketing in some transactions occurring in 2000 and 2001 should be reduced. The Company s view is that the bulk of any obligations of Mirant Americas Energy Marketing to make refunds as a result of sales completed prior to July 14, 2003, in the CAISO or Cal PX markets or in bilateral transactions either have been addressed by the California Settlement or have been resolved as part of Mirant Americas Energy Marketing s bankruptcy proceedings. To the extent that Mirant Americas Energy Marketing s potential refund liability arises from contracts that were transferred to Mirant Energy Trading as part of the transfer of the trading and marketing business under the Plan, Mirant Energy Trading may have exposure to any refund liability related to transactions under those contracts.

Complaint Challenging Capacity Rates Under the RPM Provisions of PJM s Tariff

On May 30, 2008, a variety of parties, including the state public utility commissions of Maryland, Pennsylvania, New Jersey and Delaware, ratepayer advocates, certain electric cooperatives, various groups representing industrial electricity users, and federal agencies (the RPM Buyers), filed a complaint with the FERC asserting that capacity auctions held to determine capacity payments under the reliability pricing model (RPM) provisions of PJM s tariff had produced rates that were unjust and unreasonable. PJM conducted the capacity auctions that are the subject of the complaint to set the capacity payments in effect under the RPM provisions of its tariff for twelve month periods beginning June 1, 2008, June 1, 2009, and June 1, 2010. The RPM Buyers allege that (i) the times between when the auctions were held and the periods that the resulting capacity rates would be in effect were too short to allow competition from new resources in the auctions, (ii) the administrative process established under the RPM provisions of PJM s tariff was inadequate to restrain the exercise of market power by the withholding of capacity to increase prices, and (iii) the locational pricing established under the RPM provisions of PJM s tariff created opportunities for sellers to raise prices while serving no legitimate function. The RPM Buyers asked the FERC to reduce significantly the capacity rates established by the capacity auctions and to set June 1, 2008, as the date beginning on which any rates found by the FERC to be excessive would be subject to refund. If the FERC were to reduce the capacity payments set through the capacity auctions to the rates proposed by the RPM Buyers, the capacity revenue the Company has received or expects to receive for the period June 1, 2008 through May 31, 2011, would be reduced by approximately $600 million. On September 19, 2008, the FERC issued an order dismissing the complaint. The FERC found that no party had violated the RPM provisions of PJM s tariff and that the prices determined during the auctions were in accordance with the tariff s provisions. The RPM Buyers filed a request for rehearing, which the FERC denied on June 18, 2009. Certain of the RPM Buyers have appealed the orders entered by the FERC to the United States Court of Appeals for the Fourth Circuit. That appeal has been transferred to the United States Court of Appeal for the District of Columbia Circuit.

Other Legal Matters

The Company is involved in various other claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Company s results of operations, financial position or cash flows.

L. Settlements and Other Charges

Potomac River Settlement

In July 2008, the City of Alexandria, Virginia (in which the Potomac River generating facility is located) and Mirant Potomac River entered into an agreement containing certain terms that were included in a proposed comprehensive state operating permit for the Potomac River generating facility issued by the Virginia DEQ that month. Under that agreement, Mirant Potomac River committed to spend $34 million over several years to reduce particulate emissions. The $34 million was placed in escrow and included in funds on deposit and other noncurrent assets in the accompanying unaudited condensed consolidated balance sheets. At June 30, 2010, the balance in the escrow account was approximately $33 million and is included in the Company s estimated capital expenditures. On July 30, 2008, the Virginia State Air Pollution Control Board approved the comprehensive permit with terms consistent with the agreement between Mirant Potomac and the City of Alexandria, and the Virginia DEQ issued the permit on July 31, 2008.

Prior to the issuance of the comprehensive state operating permit in July 2008, the Potomac River generating facility operated under a state operating permit issued June 1, 2007, that significantly restricted the facility s operations by imposing stringent limits on its SO2 emissions and constraining unit operations so that no more than three of the facility s five units could operate at one time. In compliance with the comprehensive permit, in 2008 Mirant Potomac River merged the stacks for units 3, 4 and 5 into one stack at the Potomac River generating facility and, in January 2009, Mirant Potomac River merged the stacks for units 1 and 2 into one stack. With the completion of the stack mergers, the permit issued in July 2008 does not constrain operations of the Potomac River generating facility below historical operations and allows operation of all five units at one time. In January 2010, the Virginia DEQ informed Mirant Potomac River that in light of the decision of the Virginia Court of Appeals vacating Virginia s rules restricting trading in CAIR allowances, the Virginia DEQ has determined that issuing a state operating permit to limit NOx emissions during the Ozone Season is warranted. In July 2010, the Virginia DEQ issued a permit that limits NOx emissions from Mirant Potomac River s generating facility to 890 tons during the Ozone Season that the Virginia DEQ asserts is effective for the 2010 Ozone Season. The Company thinks that at current market prices the new limit on NOx emissions during the Ozone Season will not have a material effect upon the Company s results of operations, financial position or cash flows.

Mirant Potrero Settlement Agreement with City of San Francisco

Mirant Potrero and the City and County of San Francisco, California entered into a Settlement Agreement (the Potrero Settlement) dated August 13, 2009. The Potrero Settlement became effective in November 2009 upon its approval by the City s Board of Supervisors and Mayor. The Potrero Settlement addressed certain disputes that had arisen between the City of

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San Francisco and Mirant Potrero related to the Potrero generating facility. Among other things, the Potrero Settlement obligates Mirant Potrero to close permanently each of the remaining units of the Potrero generating facility at the end of the year in which the CAISO determines that such unit is no longer needed to maintain the reliable operation of the electricity system. The agreement also bars Mirant Potrero from building any additional generating facilities on the site of the Potrero generating facility. Mirant Potrero expects that the completion of the TransBay Cable project, which is an underwater electric transmission cable in the San Francisco Bay, will decrease the need for generating resources in the City of San Francisco. While the TransBay Cable project has encountered some delays in startup, it is expected to become operational in 2010. As a result, Mirant Potrero expects the CAISO to determine in 2010 that unit 3 of the Potrero generating facility is no longer needed for reliability purposes and that unit 3 will close by the end of 2010. By letter dated January 12, 2010, the CAISO advised the City of San Francisco that the expected replacement in 2010 of two underground transmission cables, if completed successfully, would allow the CAISO not to require the continued operation of the remaining units of the Potrero generating facility, units 4, 5 and 6, for reliability purposes after 2010. The CAISO will not determine which units of the Potrero generating facility are required to operate in 2011 for reliability purposes until the fall of 2010. If none of the units of the Potrero generating facility will be required to operate for reliability purposes after 2010, then all of the units will close by the end of 2010.

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Item 2. Management s Discussion and Analysis of Results of Operations and Financial Condition

The following discussion should be read in conjunction with our unaudited condensed consolidated financial statements and the notes thereto, which are included elsewhere in this report.

Overview

We are a competitive energy company that produces and sells electricity in the United States. We own or lease 10,076 MW of net electric generating capacity in the Mid-Atlantic and Northeast regions and in California. We also operate an integrated asset management and energy marketing organization based in Atlanta, Georgia.

Proposed Merger with RRI Energy

On April 11, 2010, we entered into the Merger Agreement with RRI Energy and RRI Energy Holdings, Inc. (Merger Sub), a direct and wholly-owned subsidiary of RRI Energy. Upon the terms and subject to the conditions set forth in the Merger Agreement, which has been unanimously approved by each of the boards of directors of Mirant and RRI Energy, Merger Sub will merge with and into Mirant, with Mirant continuing as the surviving corporation and a wholly-owned subsidiary of RRI Energy. The merger is intended to qualify as a tax-free reorganization under the Internal Revenue Code of 1986, as amended, so that none of RRI Energy, Merger Sub, Mirant or any of the Mirant stockholders generally will recognize any gain or loss in the transaction, except that Mirant stockholders will recognize gain with respect to cash received in lieu of fractional shares of RRI Energy common stock. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Mirant common stock, including grants of restricted common stock, will automatically be converted into shares of common stock of RRI Energy based on the Exchange Ratio. Additionally, upon the closing of the merger, RRI Energy will be renamed GenOn Energy. Mirant stock options and other equity awards will generally convert upon completion of the merger into stock options and equity awards with respect to RRI Energy common stock, after giving effect to the Exchange Ratio. As a result of the merger, Mirant stockholders will own approximately 54% of the equity of the combined company and RRI Energy stockholders will own approximately 46%.

Completion of the merger is subject to various customary conditions, including, among others, (i) approval by RRI Energy stockholders of the issuance of RRI Energy common stock in the merger, (ii) adoption of the Merger Agreement by Mirant stockholders, (iii) effectiveness of the registration statement for the RRI Energy common stock to be issued in the merger, (iv) approval of the listing on the NYSE of the RRI Energy common stock to be issued in the merger, (v) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (vi) receipt of all required regulatory approvals and (vii) consummation by GenOn Energy of debt financings in an amount sufficient to fund the refinancing transactions contemplated by, and on terms consistent with, the Merger Agreement.

Among the refinancing transactions noted above, the completion of the merger is conditioned on GenOn Energy consummating certain debt financing transactions, including securing a new revolving credit facility. The new GenOn Energy debt financing and revolving credit facility will be used, in part, to redeem the Mirant North America senior notes and to repay and terminate the Mirant North America term loan and revolving credit facility. See Note D to our unaudited condensed consolidated financial statements contained elsewhere in this report and Liquidity and Capital Resources in this Item 2 for additional information on Mirant North America s debt.

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Mirant and RRI Energy are in the process of arranging mutually acceptable debt financing as contemplated under the Merger Agreement. Mirant, together with RRI Energy, have entered into agreements pursuant to which financial institutions have committed to provide a $750 million to $1.0 billion five-year revolving credit facility, subject to customary conditions to closing, including:

- the consummation of the merger;
- the receipt of at least $1.9 billion in gross cash proceeds from the issuance of senior unsecured notes and term loan borrowings; and
- the closing of the credit facility on or before December 31, 2010.

The revolving credit facility and term loan facility, and the subsidiary guarantees thereof, will be senior secured obligations of RRI Energy (proposed to be renamed GenOn Energy in connection with the merger) and certain of its subsidiaries; provided, however, that Mirant Americas Generation s subsidiaries (other than Mirant Mid-Atlantic and Mirant Energy Trading and their subsidiaries) will guarantee the revolving credit facility and term loan only to the extent permitted under the indenture for the senior notes of Mirant Americas Generation. The participating financial institutions, or affiliates thereof, have also agreed:

- to use commercially reasonable efforts to arrange a syndication of a $500 million term loan; and
- to act as underwriters or placement agents in connection with the proposed offering of senior unsecured notes.

Mirant and RRI Energy anticipate closing the proposed note offering into escrow. Upon consummation of the merger and satisfaction of the other escrow conditions, such notes will be senior unsecured obligations of GenOn Energy.

Both Mirant and RRI Energy are subject to restrictions on their ability to solicit alternative acquisition proposals, provide information and engage in discussions with third parties, except under limited circumstances to permit Mirant s and RRI Energy s boards of directors to comply with their fiduciary duties. The Merger Agreement contains certain termination rights for both Mirant and RRI Energy, and further provides that, upon termination of the Merger Agreement under specified circumstances, Mirant or RRI Energy may be required to pay the other a termination fee of either $37.15 million or $57.78 million. Further information concerning the proposed merger was included in a joint proxy statement/prospectus contained in the registration statement on Form S-4 filed by RRI Energy with the SEC on May 28, 2010, and amended on July 6, 2010.

On July 15, 2010, Mirant and RRI Energy each received a request for additional information (commonly referred to as a second request) from the Antitrust Division of the United States Department of Justice under the Hart-Scott-Rodino Act with respect to the merger. On July 20, 2010, the New York State Public Service Commission issued an order declaring that it will not further review the merger. On August 2, 2010, the FERC issued an order approving the merger.

Provided neither has experienced an ownership change between December 31, 2009, and the closing date of the merger, each of Mirant and RRI Energy is expected separately to experience an ownership change, as defined in Section (§) 382 of the Internal Revenue Code of 1986, on the merger date as a consequence of the merger. Immediately following the merger, Mirant and RRI Energy will be members of the same consolidated federal income tax group. The ability of this consolidated tax group to deduct the pre-merger NOL carry forwards of Mirant and RRI Energy against the post-merger taxable income of the group will be substantially limited as a result of these ownership changes. See Note A to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information on the proposed merger and the effect on the NOLs.

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The merger is expected to be completed by the end of 2010. Prior to the completion of the merger, Mirant and RRI Energy will continue to operate as independent companies. Except for specific references to the proposed merger and the associated debt financing transactions, the disclosures contained in this report on Form 10-Q relate solely to Mirant.

For further information concerning the proposed merger see Item 1A. Risk Factors.

Hedging Activities

We hedge economically a substantial portion of our Mid-Atlantic coal-fired baseload generation and certain of our Mid-Atlantic and Northeast gas and oil-fired generation through OTC transactions. However, we generally do not hedge our intermediate and peaking units for tenors greater than 12 months. We hedge using products which we expect to be effective to mitigate the price risk of our generation. However, as a result of market liquidity limitations, our hedges often are not an exact match for the generation being hedged, and, we then have some risks resulting from price differentials for different delivery points and for implied differences in heat rates when we hedge power using natural gas. A majority of our hedges are financial swap transactions between Mirant 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 July 13, 2010, our aggregate hedge levels based on expected generation for the remainder of 2010 and subsequent years were as follows:

	Aggregate Hedge Levels Based on Expected Generation				
	2010	2011	2012	2013	2014
Power	100%	70%	62%	33%	33%
Fuel	77%	70%	40%	9%	%

The Dodd-Frank Wall Street Reform and Consumer Protection Act (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 legislative history of the Dodd-Frank Act, including a letter from Senators Dodd and Lincoln, provides strong evidence that market participants, such as Mirant, which utilize OTC derivative financial instruments to hedge commercial risks, are not to be subject to these clearing and other requirements, it is uncertain what the implementing regulations to be issued by the Commodities Futures Trading Commission (CFTC) will provide. Greater regulation of OTC derivative financial instruments could materially affect our ability to hedge economically our generation by reducing liquidity in the energy and commodity markets, increasing hedge pricing through the imposition of capital requirements on our swap counterparties and, if we are required to clear such transactions on exchanges, by significantly increasing our requirements for cash collateral.

Capital Expenditures and Capital Resources

For the six months ended June 30, 2010, we invested $157 million for capital expenditures, excluding capitalized interest, of which $77 million related to compliance with the Maryland Healthy Air Act. As of June 30, 2010, we have invested approximately $1.482 billion for capital expenditures related to compliance with the Maryland Healthy Air Act. As the final part of our compliance with the Maryland Healthy Air Act, we placed our scrubbers in service in the fourth quarter of 2009. Provisions in our construction contracts for the scrubbers provide for certain payments to be made after final completion of the project. The current budget of $1.674 billion continues to represent our best estimate of the total capital expenditures for compliance with the Maryland Healthy Air Act. See Note K to our unaudited condensed consolidated financial statements contained elsewhere in this report for further discussion of scrubber contract issues.

For the six months ended June 30, 2010, our capitalized interest was approximately $3 million compared to $33 million for the same period in 2009. The decrease in capitalized interest from prior periods is a result of placing our scrubbers in service in the fourth quarter of 2009.

The following table details the expected timing of payments for our estimated capital expenditures, excluding capitalized interest, for the remainder of 2010 and for 2011 (in millions):

	2010	2011
Maryland Healthy Air Act	$ 192	$
Other environmental	7	33
Maintenance	45	45
Marsh Landing generating facility	45	185
Other construction	18	42
Other	13	11
Total	$ 320	$ 316

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures. However, we plan to fund a substantial portion of the capital expenditures for the Marsh Landing generating facility with project financing.

Scrubber Operating Expenses

Our capital expenditures related to compliance with the Maryland Healthy Air Act included the installation of scrubbers in the fourth quarter of 2009 at our Chalk Point, Dickerson and Morgantown coal-fired units. We incur additional operations and maintenance expenses associated with operating the scrubbers. Examples of these costs include limestone, water and chemicals used during the removal of SO2 emissions, and handling and marketing related to the recyclable gypsum byproduct created during the scrubbing process. The gypsum is sold to third parties for use in drywall production. In addition, we recognize higher depreciation expense because the scrubbers were placed in service in December 2009, and we began depreciating the capitalized costs associated with them over their expected life or, for the leased Dickerson and Morgantown generating units, their remaining lease term.

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. However, we are generally economically neutral for that portion of the generation volumes that we have hedged because our realized gross margin will reflect the contractual prices of our power and fuel contracts. We continue to add hedges opportunistically, including to maintain projected levels of cash flows from operations for future periods to help support continued compliance with the covenants in our debt and lease agreements.

As a result of the installation of the pollution control equipment at our Maryland generating facilities, we have excess SO2 and NOx emissions allowances. In July 2010, the EPA issued a proposed replacement for the CAIR. The market prices for SO2 and NOx emissions allowances continued to decline in the second quarter and declined further as a result of the proposed rule. As a result, the estimated fair value of our projected excess SO2 and NOx emissions allowances is immaterial. See Environmental and Regulatory Matters later in this section for further information on the EPA s proposed replacement of the CAIR.

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California Development Activities

Mirant Marsh Landing

On September 2, 2009, Mirant Marsh Landing entered into a ten-year PPA with PG&E for 760 MW of natural gas-fired peaking generation to be constructed adjacent to our Contra Costa generating facility near Antioch, California. Construction of the Marsh Landing generating facility is scheduled to begin in late 2010 and is expected to be completed by mid-2013.

During the ten-year term of the PPA, Mirant Marsh Landing will receive fixed monthly capacity payments and variable operating payments. The contract provides PG&E with the entire output of the 760 MW generating facility, which will be capable of producing 719 MW during peak July conditions. The Mirant Marsh Landing PPA was approved by the CPUC on July 29, 2010. The California Energy Commission also issued its preliminary approval of environmental permits on July 23, 2010, with final approval expected on August 25, 2010.

On May 6, 2010, Mirant Marsh Landing entered into an EPC Agreement with Kiewit Power Constructors Co. (Kiewit) for the construction of the Marsh Landing generating facility. Under the EPC Agreement, Kiewit is to design and construct the Marsh Landing generating facility on a turnkey basis, including all engineering, procurement, construction, commissioning, training, start-up and testing. The lump sum cost of the EPC Agreement is $499 million (including the $212 million total cost under the Siemens Turbine Generator Supply and Services Agreement which was assigned to Kiewit in connection with the execution of the EPC Agreement), plus the reimbursement of California sales and use taxes. See Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations in this Item 2 for additional information on the EPC Agreement with Kiewit.

Contra Costa Toll Extension

On September 2, 2009, Mirant Delta entered into a new agreement with PG&E for the 674 MW of Contra Costa units 6 and 7 for the period from November 2011 through April 2013. At the end of the agreement, and subject to any necessary regulatory approval, Mirant Delta has agreed to retire Contra Costa units 6 and 7, which began operations in 1964, in furtherance of state and federal policies to retire aging power plants that utilize once-through cooling technology. The new Mirant Delta agreement was approved by the CPUC on July 29, 2010.

Potrero Settlement Agreement

On August 13, 2009, Mirant Potrero entered into a Settlement Agreement (the Potrero Settlement) with the City and County of San Francisco. Among other things, the Potrero Settlement obligates Mirant Potrero to close permanently each of the remaining units of the Potrero generating facility at the end of the year in which the CAISO determines that such unit is no longer needed to maintain the reliable operation of the electricity system. Mirant Potrero expects to be notified by the CAISO by October 2010 if any of the units of the Potrero generating facility will be required to operate for reliability purposes for 2011. Otherwise, all of the units will close by the end of 2010. See Note L to our unaudited condensed consolidated financial statements contained elsewhere in this report for further discussion of the Potrero Settlement.

Mid-Atlantic Collective Bargaining Agreement

During the second quarter of 2010, we entered into a new collective bargaining agreement with our employees represented by IBEW Local 1900. The previous collective bargaining agreement expired on June 1, 2010. The new agreement has a five-year term expiring on June 1, 2015. As part of the new agreement, we are required to provide additional retirement contributions through the defined contribution plan currently sponsored by Mirant Services, increases in pay and other benefits. In addition, the new agreement provides for a change to the postretirement healthcare benefit plan covering Mid-Atlantic union employees to eliminate employer-provided healthcare subsidies through a gradual phase-out. We recorded the effects of the plan curtailment during the second quarter of 2010 and recognized a reduction in other postretirement liabilities of approximately $45 million, an increase in other comprehensive income of approximately $8 million on the unaudited condensed consolidated balance sheets and a gain of $37 million reflected as a reduction in operations and maintenance expense on the unaudited condensed consolidated statement of operations. See Note F to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information on the postretirement healthcare benefit curtailment.

Results of Operations

The following discussion of our performance is organized by reportable segment, which is consistent with the way we manage our business.

In the tables below, the Mid-Atlantic region includes our Chalk Point, Dickerson, Morgantown and Potomac River generating facilities. The Northeast region includes our Bowline, Canal, Kendall and Martha s Vineyard generating facilities. The California region includes our Contra Costa, Pittsburg and Potrero generating facilities. The California region also includes business development efforts for new generation in California, including Mirant Marsh Landing. Other Operations includes proprietary trading and fuel oil management activities. Other Operations also includes unallocated corporate overhead, interest expense on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances.

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Three Months Ended June 30, 2010 versus Three Months Ended June 30, 2009

Consolidated Financial Performance

We reported a net loss of $263 million for the three months ended June 30, 2010, compared to net income of $163 million for the three months ended June 30, 2009. The change in net income (loss) is detailed as follows (in millions):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase/ (Decrease)
Realized gross margin	$ 312	$ 360	$ (48)
Unrealized gross margin	(340)	(14)	(326)
Total gross margin	(28)	346	(374)
Operating Expenses:			
Operations and maintenance	132	114	18
Depreciation and amortization	53	36	17
Gain on sales of assets, net	(1)	(2)	1
Total operating expenses, net	184	148	36
Operating income (loss)	(212)	198	(410)
Total other expense, net	50	35	15
Income (loss) before income taxes	(262)	163	(425)
Provision for income taxes	1		1
Net income (loss)	$ (263)	$ 163	$ (426)

The following discussion includes non-GAAP financial measures because we present our consolidated financial performance in terms of gross margin. Gross margin is our operating revenue less cost of fuel, electricity and other products, and excludes depreciation and amortization. We present gross margin, excluding depreciation and amortization, as well as its two components realized gross margin and unrealized gross margin in order to be consistent with how we manage our business. Realized gross margin and unrealized gross margin are both non-GAAP financial measures. Realized gross margin represents our gross margin less unrealized gains and losses on derivative financial instruments for the periods presented. Conversely, unrealized gross margin is our unrealized gains and losses on derivative financial instruments for the periods presented. Management generally evaluates our operating results excluding the impact of unrealized gains and losses. None of our derivative financial instruments recorded at fair value is designated as a hedge 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. Adjusting our gross margin to exclude unrealized gains and losses provides a measure of performance that eliminates the volatility created by significant shifts in market values between periods. However, our realized and unrealized gross margin may not be comparable to similarly titled non-GAAP financial measures used by other companies. We encourage our investors to review our unaudited condensed consolidated financial statements and other publicly filed reports in their entirety and not to rely on a single financial measure.

For the three months ended June 30, 2010, our realized gross margin decrease of $48 million was principally a result of the following:

a decrease of $74 million in realized value of hedges. In 2010 and 2009, realized value of hedges were $78 million and $152 million, respectively, which reflects the amount by which

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- the settlement value of power contracts exceeded market prices for power, offset in part by the amount by which contract prices for fuel exceeded market prices for fuel; partially offset by

- an increase of $25 million in energy, primarily as a result of an increase in the average settlement price for power and a decrease in the cost of emissions allowances, partially offset by lower Mid-Atlantic baseload generation volumes as a result of planned outages in 2010; and

- an increase of $1 million in contracted and capacity primarily as a result of higher capacity prices in the Northeast.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $340 million in 2010, which included a $205 million net decrease in the value of hedge and proprietary trading contracts for future periods primarily related to increases in forward power prices and the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The $340 million also includes unrealized losses of $135 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods; and

- unrealized losses of $14 million in 2009, which included unrealized losses of $167 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods, partially offset by a $153 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.

Operating Expenses

Our operating expense increase of $36 million was primarily a result of the following:

- an increase of $18 million in operations and maintenance expense primarily related to the following:

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

  - an increase of $6 million in other operations and maintenance expenses; partially offset by

  - a decrease of $37 million as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering Mid-Atlantic union employees. See Note F to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information related to the postretirement healthcare benefit curtailment; and

  - a decrease of $13 million related to severance and stock-based compensation costs primarily as a result of the departure of certain executives in 2009;

an increase of $17 million in depreciation and amortization expense primarily as a result of the scrubbers that were placed in service in December 2009; and

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a decrease of $1 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Other Expense, Net

The increase of $15 million primarily reflects higher interest expense as a result of lower capitalized interest because of the scrubbers that were placed in service in December 2009.

Provision for Income Taxes

The increase of $1 million was primarily the result of federal alternative minimum tax in 2010.

Gross Margin Overview

The following tables detail realized and unrealized gross margin for the three months ended June 30, 2010 and 2009, by operating segments (in millions):

	Three Months Ended June 30, 2010					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 78	$ 4	$	$ 14	$	$ 96
Contracted and capacity	85	24	29			138
Realized value of hedges	74	4				78
Total realized gross margin	237	32	29	14		312
Unrealized gross margin	(317)	(10)		(13)		(340)
Total gross margin	$ (80)	$ 22	$ 29	$ 1	$	$ (28)

	Three Months Ended June 30, 2009					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 19	$ 3	$	$ 49	$	$ 71
Contracted and capacity	86	22	29			137
Realized value of hedges	152					152
Total realized gross margin	257	25	29	49		360
Unrealized gross margin		20		(34)		(14)
Total gross margin	$ 257	$ 45	$ 29	$ 15	$	$ 346

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

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts, through 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 coal. 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.

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

Operating Statistics

The following table summarizes Net Capacity Factor by region for the three months ended June 30, 2010 and 2009:

	Three Months Ended June 30, 2010	2009	Increase/ (Decrease)
Mid-Atlantic	30%	30%	%
Northeast	7%	7%	%
California	2%	4%	(2)%
Total	18%	18%	%

The following table summarizes power generation volumes by region for the three months ended June 30, 2010 and 2009 (in gigawatt hours):

	Three Months Ended June 30, 2010	2009	Increase/ (Decrease)	Increase/ (Decrease)
Mid-Atlantic:				
Baseload	3,062	3,441	(379)	(11)%
Intermediate	277	34	243	715%
Peaking	64	5	59	1,180%
Total Mid-Atlantic	3,403	3,480	(77)	(2)%
Northeast:				
Baseload	355	333	22	7%
Intermediate	49	38	11	29%
Peaking	1		1	100%
Total Northeast	405	371	34	9%
California:				
Intermediate	88	213	(125)	(59)%
Peaking		1	(1)	(100)%
Total California	88	214	(126)	(59)%
Total	3,896	4,065	(169)	(4)%

The total decrease in power generation volumes for the three months ended June 30, 2010, as compared to the three months ended June 30, 2009, was primarily the result of the following:

Mid-Atlantic. A decrease in our Mid-Atlantic baseload generation as a result of an increase in planned outages in 2010 compared to 2009, partially offset by an increase in our Mid-Atlantic intermediate and peaking generation.

Northeast. An increase in our Northeast baseload and intermediate generation as a result of an increase in market spark spreads.

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

Mid-Atlantic

Our Mid-Atlantic segment includes four generating facilities with total net generating capacity of 5,194 MW.

The following table summarizes the results of operations of our Mid-Atlantic segment (in millions):

	Three Months Ended June 30,		
	2010	**2009**	**Increase/ (Decrease)**
Gross Margin:			
Energy	$ 78	$ 19	$ 59
Contracted and capacity	85	86	(1)
Realized value of hedges	74	152	(78)
Total realized gross margin	237	257	(20)
Unrealized gross margin	(317)		(317)
Total gross margin	(80)	257	(337)
Operating Expenses:			
Operations and maintenance	117	101	16
Depreciation and amortization	36	24	12
Gain on sales of assets, net	(1)	(2)	1
Total operating expenses, net	152	123	29
Operating income (loss)	(232)	134	(366)
Total other expense, net	1	1	
Net income (loss)	$ (233)	$ 133	$ (366)

Gross Margin

The decrease of $20 million in realized gross margin was principally a result of the following:

- a decrease of $78 million in realized value of hedges. In 2010 and 2009, realized value of hedges were $74 million and $152 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for coal exceeded market prices for coal; and

- a decrease of $1 million in contracted and capacity primarily related to lower average capacity prices, offset in part by additional megawatts of capacity sold in 2010; partially offset by an increase of $59 million in energy, primarily as a result of an increase in the average settlement price for power, a decrease in the cost of emissions allowances and higher intermediate and peaking generation volumes, partially offset by an increase in the price of coal and lower baseload generation volumes.

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Our unrealized gross margin for both periods reflects the following:

unrealized losses of $317 million in 2010, which included a $203 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices and the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The $317 million also includes unrealized losses of $114 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods; and

unrealized gross margin in 2009 included a $123 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, offset by unrealized losses of $123 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods.

Operating Expenses

Our operating expense increase of $29 million was primarily a result of the following:

an increase of $16 million in operations and maintenance expense primarily as a result of an increase in costs related to the operation of our scrubbers and an increase in planned outages in 2010 compared to 2009;

an increase of $12 million in depreciation and amortization expense primarily as a result of the scrubbers that were placed in service in December 2009, offset in part by a decrease in the carrying value of the Potomac River generating facility as a result of the impairment charge taken in the fourth quarter of 2009; and

a decrease of $1 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Northeast

Our Northeast segment is comprised of our three generating facilities located in Massachusetts and one generating facility located in New York with total net generating capacity of 2,535 MW.

The following table summarizes the results of operations of our Northeast segment (in millions):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase/ (Decrease)
Gross Margin:			
Energy	$ 4	$ 3	$ 1
Contracted and capacity	24	22	2
Realized value of hedges	4		4
Total realized gross margin	32	25	7
Unrealized gross margin	(10)	20	(30)
Total gross margin	22	45	(23)
Operating Expenses:			
Operations and maintenance	27	35	(8)

Depreciation and amortization	6	5	1
Total operating expenses, net	33	40	(7)
Operating income (loss)	(11)	5	(16)
Total other expense, net	1		1
Net income (loss)	$ (12)	$ 5	$ (17)

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Gross Margin

The increase of $7 million in realized gross margin was principally a result of the following:

- an increase of $4 million in realized value of hedges. In 2010, realized value of hedges was $4 million, which reflects the amount by which the settlement value of power contracts exceeded market prices, offset by the amount by which contract prices for fuel exceeded market prices for fuel;

- an increase of $2 million in contracted and capacity primarily related to higher capacity prices in 2010; and

- an increase of $1 million in energy primarily as a result of higher generation volumes.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $10 million in 2010, which included a $6 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power and fuel prices and unrealized losses of $4 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods; and

- unrealized gains of $20 million in 2009, which included a $29 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and fuel prices, partially offset by unrealized losses of $9 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods.

Operating Expenses

Our operating expense decrease of $7 million was primarily a result of a decrease in shutdown costs associated with the demolished Lovett generating facility, a decrease in property taxes because of a lower assessed value for the site of the demolished Lovett generating facility and a decrease in costs related to planned outages in 2010 compared to 2009 for our other generating facilities.

California

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

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The following table summarizes the results of operations of our California segment (in millions):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase/ (Decrease)
Gross Margin:			
Contracted and capacity	$ 29	$ 29	$
Total realized gross margin	29	29	
Unrealized gross margin			
Total gross margin	29	29	
Operating Expenses:			
Operations and maintenance	18	24	(6)
Depreciation and amortization	7	5	2
Total operating expenses, net	25	29	(4)
Net income	$ 4	$	$ 4

Gross Margin

All of our California generating facilities operate under tolling agreements or are subject to RMR arrangements. Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for 100% of the capacity from these units, and our Potrero units are subject to RMR arrangements. Therefore, our gross margin generally is not affected by changes in power generation volumes from those facilities.

Operating Expenses

Our operating expense decrease of $4 million was primarily a result of a decrease in outages and property taxes, partially offset by an increase in depreciation expense as a result of a decrease in the useful life of our Potrero generating facility because of the settlement with the City of San Francisco executed in the third quarter of 2009. See Note L to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information on the Mirant Potrero settlement with the City of San Francisco.

Other Operations

Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest expense on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances.

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The following table summarizes the results of operations of our Other Operations segment (in millions):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase/ (Decrease)
Gross Margin:			
Energy	$ 14	$ 49	$ (35)
Total realized gross margin	14	49	(35)
Unrealized gross margin	(13)	(34)	21
Total gross margin	1	15	(14)
Operating Expenses:			
Operations and maintenance	(30)	(46)	16
Depreciation and amortization	4	2	2
Total operating expenses (income), net	(26)	(44)	18
Operating income	27	59	(32)
Total other expense, net	48	34	14
Income (loss) before income taxes	$ (21)	$ 25	$ (46)

Gross Margin

The decrease of $35 million in realized gross margin was principally a result of a $40 million decrease in gross margin from our fuel oil management activities, partially offset by a $5 million increase in gross margin from proprietary trading activities. The decrease in the contribution from fuel oil management was a result of lower gross margin on positions used to hedge economically the fair value of our physical fuel oil inventory. The increase in the contribution from proprietary trading was a result of an increase in the realized value associated with trading positions in 2010 as compared to 2009.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $13 million in 2010, which included unrealized losses of $17 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods, partially offset by a $4 million net increase in the value of contracts for future periods; and

- unrealized losses of $34 million in 2009, which included unrealized losses of $35 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods, partially offset by a $1 million net increase in the value of contracts for future periods.

Operating Expenses

The increase of $18 million in operating expenses was principally the result of the following:

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

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- an increase of $3 million related to merger-related costs incurred in 2010; partially offset by

- a decrease of $37 million in operations and maintenance primarily as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering Mid-Atlantic union employees. See Note F to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information related to the postretirement healthcare benefit curtailment; and

- a decrease of $13 million related to severance and stock-based compensation costs primarily as a result of the departure of certain executives in 2009.

Other Expense, Net

The increase of $14 million in other expense, net was principally the result of an increase of $15 million in interest expense primarily related to lower capitalized interest because of the scrubbers that were placed in service in December 2009.

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Six Months Ended June 30, 2010 versus Six Months Ended June 30, 2009

Consolidated Financial Performance

We reported net income of $144 million and $543 million for the six months ended June 30, 2010 and 2009, respectively. The change in net income is detailed as follows (in millions):

	Six Months Ended June 30, 2010	2009	Increase/ (Decrease)
Realized gross margin	$ 633	$ 713	$ (80)
Unrealized gross margin	12	240	(228)
Total gross margin	645	953	(308)
Operating Expenses:			
Operations and maintenance	298	276	22
Depreciation and amortization	104	72	32
Gain on sales of assets, net	(3)	(17)	14
Total operating expenses, net	399	331	68
Operating income	246	622	(376)
Total other expense, net	101	71	30
Income before income taxes	145	551	(406)
Provision for income taxes	1	8	(7)
Net income	$ 144	$ 543	$ (399)

Gross Margin

For the six months ended June 30, 2010, our realized gross margin decrease of $80 million was principally a result of the following:

- a decrease of $113 million in realized value of hedges. In 2010 and 2009, realized value of hedges were $147 million and $260 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, offset in part by the amount by which contract prices for fuel exceeded market prices for fuel; partially offset by

- an increase of $24 million in energy, primarily as a result of an increase in the average settlement price for power and a decrease in the cost of emissions allowances, partially offset by lower generation volumes; and

- an increase of $9 million in contracted and capacity primarily as a result of higher capacity revenues in California, higher capacity prices in the Northeast and an increase in ancillary services revenue and additional megawatts of capacity sold in Mid-Atlantic.

Our unrealized gross margin for both periods reflects the following:

unrealized gains of $12 million in 2010, which included a $228 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 also includes the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value is partially offset by unrealized losses of $216 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods; and

unrealized gains of $240 million in 2009, which included a $494 million net increase in the value of hedge and proprietary trading contracts for future periods primarily related to

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decreases in forward power and natural gas prices, partially offset by unrealized losses of $254 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods.

Operating Expenses

Our operating expense increase of $68 million was primarily a result of the following:

- an increase of $22 million in operations and maintenance expense primarily related to the following:
  - an increase of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, including a $52 million reduction in operations and maintenance expense for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed, and a $10 million reversal of accruals for future funding to MC Asset Recovery. See Note K to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information related to the settlement between MC Asset Recovery and Southern Company; and
  - an increase of $9 million in other operations and maintenance expenses; partially offset by
  - a decrease of $37 million as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering Mid-Atlantic union employees. See Note F to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information related to the postretirement healthcare benefit curtailment; and
  - a decrease of $12 million related to severance and stock-based compensation costs primarily as a result of the departure of certain executives in 2009;
- an increase of $32 million in depreciation and amortization expense primarily as a result of the scrubbers that were placed in service in December 2009; and
- a decrease of $14 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Other Expense, Net

The increase of $30 million primarily reflects higher interest expense as a result of lower capitalized interest because of the scrubbers that were placed in service in December 2009.

Provision for Income Taxes

The decrease of $7 million was primarily a result of $5 million of federal alternative minimum tax for 2009 and $3 million in California income taxes as a result of the state s suspension of the utilization of NOL carry forwards for the 2008 and 2009 tax years, offset by $1 million of federal alternative minimum tax for 2010.

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Gross Margin Overview

The following tables detail realized and unrealized gross margin for the six months ended June 30, 2010 and 2009, by operating segments (in millions):

	Six Months Ended June 30, 2010					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 170	$ 1	$	$ 35	$	$ 206
Contracted and capacity	174	47	59			280
Realized value of hedges	131	16				147
Total realized gross margin	475	64	59	35		633
Unrealized gross margin	29	(14)		(3)		12
Total gross margin	$ 504	$ 50	$ 59	$ 32	$	$ 645

	Six Months Ended June 30, 2009					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 91	$ 18	$	$ 76	$ (3)	$ 182
Contracted and capacity	171	44	56			271
Realized value of hedges	259	1				260
Total realized gross margin	521	63	56	76	(3)	713
Unrealized gross margin	243	46		(49)		240
Total gross margin	$ 764	$ 109	$ 56	$ 27	$ (3)	$ 953

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

Contracted and capacity represents gross margin received from capacity sold in ISO and RTO administered capacity markets, through RMR contracts, through 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 coal. Power hedging contracts include sales of both power and natural gas used to hedge power prices, as well as hedges to capture the incremental value related to the geographic location of our physical assets.

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

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Operating Statistics

The following table summarizes Net Capacity Factor by region for the six months ended June 30, 2010 and 2009:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase/ (Decrease)
Mid-Atlantic	32%	32%	%
Northeast	7%	12%	(5)%
California	2%	4%	(2)%
Total	19%	20%	(1)%

The following table summarizes power generation volumes by region for the six months ended June 30, 2010 and 2009 (in gigawatt hours):

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase/ (Decrease)	Increase/ (Decrease)
Mid-Atlantic:				
Baseload	7,034	7,167	(133)	(2)%
Intermediate	332	139	193	139%
Peaking	70	36	34	94%
Total Mid-Atlantic	7,436	7,342	94	1%
Northeast:				
Baseload	720	698	22	3%
Intermediate	58	572	(514)	(90)%
Peaking	1		1	100%
Total Northeast	779	1,270	(491)	(39)%
California:				
Intermediate	211	389	(178)	(46)%
Peaking		1	(1)	(100)%
Total California	211	390	(179)	(46)%
Total	8,426	9,002	(576)	(6)%

The total decrease in power generation volumes for the six months ended June 30, 2010, as compared to the six months ended June 30, 2009, was primarily the result of the following:

Mid-Atlantic. An increase in our Mid-Atlantic intermediate and peaking generation, partially offset by an increase in planned outages for our baseload generation in 2010 compared to 2009.

Northeast. A decrease in our Northeast intermediate generation as a result of transmission upgrades in 2009 which reduced the demand for the oil-fired intermediate units at our Canal generating facility.

California. All of our California generating facilities operate under tolling agreements or are subject to RMR arrangements. Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for 100% of the capacity from these units

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and our Potrero units are subject to RMR arrangements. Therefore, changes in power generation volumes from those generating facilities, which can be caused by weather, planned outages or other factors, generally do not affect our gross margin.

Mid-Atlantic

Our Mid-Atlantic segment includes four generating facilities with total net generating capacity of 5,194 MW.

The following table summarizes the results of operations of our Mid-Atlantic segment (in millions):

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase/ (Decrease)
Gross Margin:			
Energy	$ 170	$ 91	$ 79
Contracted and capacity	174	171	3
Realized value of hedges	131	259	(128)
Total realized gross margin	475	521	(46)
Unrealized gross margin	29	243	(214)
Total gross margin	504	764	(260)
Operating Expenses:			
Operations and maintenance	230	206	24
Depreciation and amortization	69	48	21
Gain on sales of assets, net	(3)	(10)	7
Total operating expenses, net	296	244	52
Operating income	208	520	(312)
Total other expense, net	2	2	
Net income	$ 206	$ 518	$ (312)

Gross Margin

The decrease of $46 million in realized gross margin was principally a result of the following:

- a decrease of $128 million in realized value of hedges. In 2010 and 2009, realized value of hedges were $131 million, and $259 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for coal exceeded market prices for coal; partially offset by

- an increase of $79 million in energy, primarily as a result of an increase in the average settlement price for power, a decrease in the cost of emissions allowances and higher intermediate and peaking generation volumes, partially offset by lower baseload generation volumes; and an increase of $3 million in contracted and capacity primarily related to ancillary services revenue and additional megawatts of capacity sold in 2010, partially offset by lower average capacity prices.

Our unrealized gross margin for both periods reflects the following:

- unrealized gains of $29 million in 2010, which included a $193 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices and also includes the recognition of many of our coal agreements at fair value beginning in the second quarter of 2010. The increase in value is partially offset by unrealized losses of $164 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods; and

- unrealized gains of $243 million in 2009, which included a $434 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and natural gas prices, partially offset by unrealized losses of $191 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods.

Operating Expenses

Our operating expense increase of $52 million was primarily a result of the following:

- an increase of $24 million in operations and maintenance expense primarily as a result of an increase in costs related to the operation of our scrubbers and an increase in planned outages in 2010 compared to 2009;

- an increase of $21 million in depreciation and amortization expense primarily as a result of the scrubbers that were placed in service in December 2009, offset in part by a decrease in the carrying value of the Potomac River generating facility as a result of the impairment charge taken in the fourth quarter of 2009; and

- a decrease of $7 million in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009.

Northeast

Our Northeast segment is comprised of our three generating facilities located in Massachusetts and one generating facility located in New York with total net generating capacity of 2,535 MW.

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The following table summarizes the results of operations of our Northeast segment (in millions):

	Six Months Ended June 30, 2010	2009	Increase/ (Decrease)
Gross Margin:			
Energy	$ 1	$ 18	$ (17)
Contracted and capacity	47	44	3
Realized value of hedges	16	1	15
Total realized gross margin	64	63	1
Unrealized gross margin	(14)	46	(60)
Total gross margin	50	109	(59)
Operating Expenses:			
Operations and maintenance	51	67	(16)
Depreciation and amortization	12	9	3
Gain on sales of assets, net		(2)	2
Total operating expenses, net	63	74	(11)
Operating income (loss)	(13)	35	(48)
Total other expense, net	1		1
Net income (loss)	$ (14)	$ 35	$ (49)

Gross Margin

The increase of $1 million in realized gross margin was principally a result of the following:

an increase of $15 million in realized value of hedges. In 2010 and 2009, realized value of hedges were $16 million and $1 million, respectively, which reflects the amount by which the settlement value of power contracts exceeded market prices for power, partially offset by the amount by which contract prices for fuel exceeded market prices for fuel; and

an increase of $3 million in contracted and capacity primarily related to higher capacity prices in 2010; partially offset by

a decrease of $17 million in energy primarily as a result of a decrease in generation volumes from our oil-fired intermediate units as a result of transmission upgrades in 2009.

Our unrealized gross margin for both periods reflects the following:

unrealized losses of $14 million in 2010, which included unrealized losses of $14 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods; and unrealized gains of $46 million in 2009, which included a $54 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power and fuel prices; partially offset by unrealized losses of $8 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods.

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Operating Expenses

Our operating expense decrease of $11 million was primarily a result of a decrease in shutdown costs associated with the demolished Lovett generating facility and a decrease in property taxes because of a lower assessed value for the site of the demolished Lovett generating facility.

California

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

The following table summarizes the results of operations of our California segment (in millions):

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase/ (Decrease)
Gross Margin:			
Contracted and capacity	$ 59	$ 56	$ 3
Total realized gross margin	59	56	3
Unrealized gross margin			
Total gross margin	59	56	3
Operating Expenses:			
Operations and maintenance	38	43	(5)
Depreciation and amortization	15	10	5
Gain on sales of assets, net		(1)	1
Total operating expenses, net	53	52	1
Operating income	6	4	2
Total other expense, net		1	(1)
Net income	$ 6	$ 3	$ 3

Gross Margin

All of our California generating facilities operate under tolling agreements or are subject to RMR arrangements. Our natural gas-fired units in service at Contra Costa and Pittsburg operate under tolling agreements with PG&E for 100% of the capacity from these units, and our Potrero units are subject to RMR arrangements. Therefore, our gross margin generally is not affected by changes in power generation volumes from those facilities.

Operating Expenses

Our operating expense increase of $1 million was primarily a result of an increase in depreciation expense as a result of a decrease in the useful life of our Potrero generating facility because of the settlement with the City of San Francisco executed in the third quarter of 2009 and a decrease in gain on sales of assets primarily related to emissions allowances sold to third parties in 2009, partially offset by a decrease in outages and property taxes. See Note L to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information on the Mirant Potrero settlement with the City of San Francisco.

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Other Operations

Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest expense on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances.

The following table summarizes the results of operations of our Other Operations segment (in millions):

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase/ (Decrease)
Gross Margin:			
Energy	$ 35	$ 76	$ (41)
Total realized gross margin	35	76	(41)
Unrealized gross margin	(3)	(49)	46
Total gross margin	32	27	5
Operating Expenses:			
Operations and maintenance	(21)	(40)	19
Depreciation and amortization	8	5	3
Total operating expenses (income), net	(13)	(35)	22
Operating income	45	62	(17)
Total other expense, net	98	68	30
Loss before income taxes	$ (53)	$ (6)	$ (47)

Gross Margin

The decrease of $41 million in realized gross margin was principally a result of a $33 million decrease in gross margin from our fuel oil management activities and an $8 million decrease in gross margin from proprietary trading activities. The decrease in the contribution from fuel oil management was a result of lower gross margin on positions used to hedge economically the fair value of our physical fuel oil inventory. The decrease in the contribution from proprietary trading was primarily a result of a decrease in the realized value associated with power positions in 2010 as compared to 2009.

Our unrealized gross margin for both periods reflects the following:

- unrealized losses of $3 million in 2010, which included unrealized losses of $38 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods, partially offset by a $35 million net increase in the value of contracts for future periods; and

- unrealized losses of $49 million in 2009, which included unrealized losses of $54 million from power and fuel contracts that settled during the period for which net unrealized gains had been recorded in prior periods, partially offset by a $5 million net increase in the value of contracts for future periods.

Operating Expenses

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

- an increase of $62 million related to the MC Asset Recovery settlement with Southern Company in 2009, including a $52 million reduction in operations and maintenance expense

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for the reimbursement of funds provided to MC Asset Recovery and costs incurred related to MC Asset Recovery not previously reimbursed, and a $10 million reversal of accruals for future funding to MC Asset Recovery. See Note K to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information related to the settlement between MC Asset Recovery and Southern Company; and

an increase of $5 million related to merger-related costs incurred in 2010; partially offset by

a decrease of $37 million in operations and maintenance primarily as a result of a curtailment gain resulting from an amendment to our postretirement healthcare benefits plan covering Mid-Atlantic union employees. See Note F to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information related to the postretirement healthcare benefit curtailment; and

a decrease of $13 million related to severance and stock-based compensation costs primarily as a result of the departure of certain executives in 2009.

Other Expense, Net

The increase of $30 million in other expense, net was principally the result of an increase of $28 million in interest expense primarily related to lower capitalized interest because of the scrubbers that were placed in service in December 2009.

Financial Condition

Liquidity and Capital Resources

We expect that we will have sufficient liquidity for our future operations and capital expenditures, and to service our debt obligations. We regularly monitor our ability to finance the needs of our operating, investing and financing activities. See Note D to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional discussion of our debt.

Sources of Funds

The principal sources of our liquidity are expected to be: (1) existing cash on hand (including approximately $1.4 billion at Mirant Corporation) and expected cash flows from the operations of our subsidiaries, (2) letters of credit issued or borrowings made under Mirant North America s senior secured revolving credit facility, (3) letters of credit issued under Mirant North America s senior secured term loan and (4) planned project financing for the Mirant Marsh Landing generating facility. As described in Overview in this Item 2, the completion of the proposed merger with RRI Energy is conditioned on GenOn Energy consummating certain debt financing transactions, including securing a new revolving credit facility. The new GenOn Energy debt financing and revolving credit facility will be used, in part, to redeem the Mirant North America senior notes and to repay and terminate the Mirant North America term loan and revolving credit facility.

The table below sets forth total cash, cash equivalents and availability under credit facilities of Mirant and its subsidiaries (in millions):

	At June 30, 2010	At December 31, 2009
Cash and Cash Equivalents:		
Mirant Corporation	$ 1,388	$ 1,524
Mirant Americas Generation		1
Mirant North America	272	278
Mirant Mid-Atlantic	159	125
Other	30	25
Total cash and cash equivalents	1,849	1,953
Less: cash restricted and reserved for other purposes	(11)	(11)
Total available cash and cash equivalents	1,838	1,942
Available under credit facilities	662	680
Total cash, cash equivalents and credit facilities availability	$ 2,500	$ 2,622

We consider all short-term investments with an original maturity of three months or less to be cash equivalents. At June 30, 2010 and December 31, 2009, 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.

Available under credit facilities at June 30, 2010 and December 31, 2009, reflects a $45 million effective reduction as a result of the bankruptcy filing of Lehman Commercial Paper, Inc., a lender under the Mirant North America senior secured revolving credit facility.

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

Except for existing cash on hand and, in the case of Mirant North America, borrowings and letters of credit under its credit facilities, the Mirant Corporation, Mirant Americas Generation and Mirant North America holding companies are dependent for liquidity on the distributions and dividends of their subsidiaries. The ability of Mirant North America and its subsidiary, Mirant Mid-Atlantic, to make distributions and pay dividends is restricted under the terms of their debt agreements and leveraged lease documentation, respectively. At June 30, 2010, Mirant North America had distributed to its parent, Mirant Americas Generation, all available cash that was permitted to be distributed under the terms of its debt agreements, leaving $431 million at Mirant North America and its subsidiaries. Of this amount, $159 million was held by Mirant Mid-Atlantic which, as of June 30, 2010, met the tests under the leveraged lease documentation permitting it to make distributions to Mirant North America. After taking into account the financial results of Mirant North America for the six months ended June 30, 2010, we expect Mirant North America will distribute approximately $110 million to its parent, Mirant Americas Generation, in August 2010. Although we expect Mirant North America to remain in compliance with its financial covenants in future periods, and to have sufficient liquidity and capital resources to meet its obligations, it is likely that it will be restricted from making distributions by the free cash flow requirements under the restricted payment test of its senior credit facility in future periods. The primary factor lowering the free cash flow calculation for Mirant North America is the significant capital expenditure program of Mirant Mid-Atlantic to install emissions controls at its Chalk Point, Dickerson and Morgantown coal-fired units to comply with the Maryland Healthy Air Act. When the capital expenditures no longer affect the calculation of its free cash flow, Mirant North America is expected to be able again to make distributions. We do not expect the liquidity effect of the restriction on distributions under the Mirant North America senior credit facility to be material given that the majority of our liquidity needs arise from the activities of Mirant North America and its subsidiaries, the restriction does not limit Mirant North America from making distributions to Mirant Americas Generation to fund interest payments on its senior notes and the majority of our total available cash and cash equivalents is held unrestricted at Mirant Corporation.

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 activities: (1) capital expenditures, (2) debt service and payments under the Mirant Mid-Atlantic leveraged leases, (3) collateral required for our asset management and proprietary trading and fuel oil management activities and (4) the development of new generating facilities, in particular, the Mirant Marsh Landing generating facility.

Capital Expenditures. Our capital expenditures, excluding capitalized interest for the six months ended June 30, 2010, were $157 million. Our estimated capital expenditures, excluding capitalized interest, for the period July 1, 2010, through December 31, 2011, are expected to be $636 million. See Capital Expenditures and Capital Resources in this Item 2 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 to access the transmission grid, to participate in power pools, to fund debt service and rent reserves and for 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. As of June 30, 2010, we had approximately $77 million of posted cash collateral and $228 million of letters of credit outstanding primarily to support our asset management activities, trading activities, debt service and rent reserve requirements, and other commercial arrangements. Included in the letter of credit amount outstanding is a $12 million cash-collateralized letter of credit in support of the Mirant Marsh Landing PPA with PG&E, which amount is expected to increase in the third quarter to approximately $80 million as a result of the approval of the PPA by the CPUC on July 29, 2010. Our liquidity requirements are highly dependent on the level of our hedging activities, forward prices for energy, emissions allowances and fuel, commodity market volatility, credit terms with third parties and regulation of energy contracts. See Item 1A Risk Factors for our discussion on the Dodd-Frank Act. See Note E to our unaudited condensed consolidated financial statements contained elsewhere in this report for additional information.

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

	At June 30, 2010	At December 31, 2009
Cash collateral posted energy trading and marketing	$ 36	$ 41
Cash collateral posted other operating activities	41	43
Letters of credit energy trading and marketing	69	51
Letters of credit debt service and rent reserves	107	101
Letters of credit other operating activities	52	59
Surety bonds	6	5
Total	$ 311	$ 300

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

Marsh Landing Generating Facility EPC Agreement

On May 6, 2010, Mirant Marsh Landing entered into an EPC Agreement with Kiewit for the construction of the Marsh Landing generating facility. Under the EPC Agreement, Kiewit is to design and construct the Marsh Landing generating facility on a turnkey basis, including all engineering, procurement, construction, commissioning, training, start-up and testing. The lump sum cost of the EPC Agreement is $499 million (including the $212 million total cost under the Siemens Turbine Generator Supply and Services Agreement which was assigned to Kiewit in connection with the execution of the EPC Agreement), plus the reimbursement of California sales and use taxes due under the Siemens Turbine Generator Supply and Services Agreement.

As security for its obligations, Kiewit will provide a corporate guarantee from Kiewit Construction Company of its obligations under the EPC Agreement and a letter of credit in the amount of $31.8 million, reducing to $10.6 million upon substantial completion of the Marsh Landing generating facility. Likewise, Mirant Marsh Landing will provide a corporate guarantee from Mirant Corporation in an amount not to exceed $43.0 million and a letter of credit in an amount up to $72.0 million, as security for the termination amount from time to time under the turbine equipment supply contract assumed by Kiewit upon execution of the EPC Agreement. In addition, as further security for successful completion of the work, Mirant Marsh Landing is retaining a portion of the payments made to Kiewit under the EPC Agreement which will be paid to Kiewit in two disbursements, one upon substantial completion of the Marsh Landing generating facility (including successful performance testing and commercial operation) and the other at final completion.

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 $234 million for the six months ended June 30, 2010, compared to the same period in 2009, primarily as a result of the following:

Realized gross margin. A decrease in cash provided of $82 million in 2010, compared to the same period in 2009, excluding a decrease in non-cash lower of cost or market fuel inventory adjustments of $2 million. See Results of Operations in this Item 2 for additional discussion of our performance in 2010 compared to the same period in 2009;

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Inventories. An increase in cash used of $46 million primarily as a result of larger volumes of fuel oil purchased at higher prices in 2010 as compared to 2009;

Accounts payable, collateral. An increase in cash used of $43 million as a result of $1 million received from counterparties in 2010 as compared to $44 million received from counterparties in 2009;

Interest expense, net. An increase in cash used of $30 million primarily as a result of a decrease in capitalized interest which is included in investing activities;

Funds on deposit. A decrease in cash provided of $24 million. We received an additional $6 million in collateral returned from our counterparties in 2010 compared to an additional $30 million received in 2009; and

Other operating assets and liabilities. An increase in cash used of $9 million related to changes in other operating assets and liabilities.

Investing Activities. Net cash used in investing activities decreased by $176 million for the six months ended June 30, 2010, compared to the same period in 2009. This difference was primarily a result of the following:

Capital expenditures. A decrease in cash used of $218 million, including $30 million related to a decrease in capitalized interest, primarily related to placing scrubbers for our Maryland generating facilities in service in the fourth quarter of 2009 as part of our compliance with the Maryland Healthy Air Act; and

Capital contributions paid to subsidiaries. A decrease in cash used of $5 million related to our obligation to fund MC Asset Recovery in 2009 which, in 2010, we are no longer obligated to fund; partially offset by

Proceeds from the sales of assets. A decrease in cash provided of $14 million primarily related to the sales of emissions allowances in 2009 as compared to 2010; and

Payments into restricted deposits. An increase in cash used of $33 million primarily related to the funding of a Rabbi Trust established to fund severance payments for certain key employees in connection with the proposed merger with RRI Energy.

Financing Activities. Net cash used in financing activities increased by $28 million for the six months ended June 30, 2010, compared to the same period in 2009. This difference was primarily a result of the repayment of long-term debt.

Discontinued Operations

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

Environmental and Regulatory Matters

Regulation of Greenhouse Gases, including the RGGI. Concern over climate change has led to significant legislative and regulatory efforts at the state and federal level to limit greenhouse gas emissions, especially CO2. One such effort is the RGGI, a multi-state initiative in the Mid-Atlantic and Northeast outlining a cap-and-trade program to reduce CO2 emissions from electric generating units with capacity of 25 MW or greater. The RGGI program calls for signatory states, which include Maryland, Massachusetts and New York, to stabilize CO2 emissions to an

established baseline from 2009 through 2014, followed by a 2.5% reduction each year from 2015 through 2018. Each of these three states has promulgated regulations implementing the RGGI. Complying with the RGGI could have a material adverse effect upon our operations and our operating costs, depending upon the availability and cost of emissions allowances and the extent to which such costs may be offset by higher market prices to recover increases in operating costs caused by the RGGI.

During 2009, we produced approximately 14.6 million tons of CO2 at our Maryland, Massachusetts and New York generating facilities for a total cost of $45 million under the RGGI. In 2010, we expect to produce approximately 17.1 million tons of CO2 at our Maryland, Massachusetts and New York generating facilities. The RGGI regulations required those facilities to obtain allowances to emit CO2 beginning in 2009. Annual allowances generally were not granted to existing sources of such emissions. Instead, allowances have been made available for such facilities by purchase through periodic auctions conducted quarterly or through subsequent purchase from a party that holds allowances sold through a quarterly auction process. The Maryland regulations implementing the RGGI, which were amended on May 8, 2009, also provide that if the allowance clearing price reaches or exceeds $7 per ton of CO2 in the auctions of allowances that occur during 2009 to 2011 for the current year s allowances, Maryland will withhold the remainder of that year s allowances from sale in any future auction during that calendar year and make those allowances available by direct sale to generators in Maryland. In this scenario, between 0% and 50% of Maryland s allowances allocated for sale in that year may be made available for purchase by such generators. Any such allowances made available for each generator to purchase at $7 per ton will be in proportion to each generator s annual average heat input during specified historical periods as compared to the total average input for all affected Maryland generators in existence at that time. In none of the auctions held to date has the price reached $7 per ton.

The eighth auction of allowances by the RGGI states was held on June 9, 2010. The clearing price for the approximately 41 million allowances sold in the auction allocated for use beginning in 2009 was $1.88 per ton. Allowances allocated for use beginning in 2012 were also made available, and substantially all of the 2.1 million allowances available at the auction were sold at a price of $1.86 per ton. The allowances sold in this auction may be used for compliance in any of the RGGI states. Further auctions will occur quarterly through the end of the first compliance period in 2011, with the next auction scheduled for September 8, 2010.

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 California Air Resources Board (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 Western Climate Initiative (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. AB 32, and any plans, rules and programs approved to implement AB 32, could have a material adverse effect on how we operate our California generating facilities and the costs of operating the facilities.

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

In April 2009, the Maryland General Assembly passed the Greenhouse Gas Reduction Act of 2009 (the Maryland Act), which became effective in October 2009. The Maryland Act requires a reduction in greenhouse gas emissions in Maryland by 25% from 2006 levels by 2020. However, this provision of the Maryland Act is only in effect through 2016 unless a subsequent statutory enactment extends its effective period. The Maryland Act requires the MDE to develop a proposed implementation plan to achieve these reductions by the end of 2011 and to adopt a final plan by the end of 2012.

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

Various bills have been proposed in Congress to govern CO2 emissions from generating facilities. Current proposals include a cap-and-trade system that would require us to purchase allowances for some or all of the CO2 emitted by our generating facilities. Although we expect that market prices for electricity would increase following such legislation and would allow us to recover a portion of the cost of these allowances, we cannot predict with any certainty the actual increases in costs such legislation could impose upon us or our ability to recover such cost increases through higher market rates for electricity, and such legislation could have a material adverse effect on our consolidated statements of operations, financial position and cash flows. It is possible that Congress will take action to regulate greenhouse gas emissions within the next several years. The form and timing of any final legislation will be influenced by political and economic factors and is uncertain at this time. During 2009, we produced approximately 16.1 million tons of CO_2 at our generating facilities. We expect to produce approximately 19 million total tons of CO_2 at our generating facilities in 2010.

Clean Air Interstate Rule. In 2005, the EPA promulgated the CAIR, which established in the eastern United States SO_2 and NOx cap-and-trade programs applicable directly to states and indirectly to generating facilities. The NOx 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 of 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. Maryland, New York and Virginia are subject to the CAIR s SO_2 and both NOx trading programs. Massachusetts is subject only to the CAIR s Ozone Season NOx trading program. These cap-and-trade programs were to be implemented in two phases, with the first phase going into effect in 2009 for NOx and 2010 for SO_2 and more stringent caps going into effect in 2015. Various parties challenged the EPA s adoption of the CAIR, and on July 11, 2008, the DC 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 DC Circuit and on December 23, 2008, the DC 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 DC Circuit s opinions. The four states in which we operate that are subject to CAIR (i.e., Maryland, Massachusetts, New York and Virginia) have promulgated regulations implementing the federal CAIR.

The EPA has stated that it expects to finalize the regulations to replace the CAIR in 2011, and on August 2, 2010, the EPA proposed a rule to replace the CAIR and two possible alternatives. If finalized, the CAIR replacement proposal and each of the alternatives would impose more stringent emission reductions than were required under the CAIR. The EPA s proposed replacement rule would establish an emissions budget for each of thirty-one eastern and midwestern states and the District of Columbia, and would allow only limited interstate trading. For SO_2, generating facilities in a region comprised of Illinois, Indiana, Iowa, Georgia, Kentucky, Ohio, Michigan, Missouri, New York, North Carolina, Pennsylvania, Tennessee, Virginia, West Virginia and Wisconsin would be subject to a more stringent cap on SO_2 emissions than the other states subject to the rule, and would not be allowed to use emissions allowances from sources in a separate region comprised of Alabama, Delaware, the District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey, Rhode Island and South Carolina. For both SO_2 and NOx, interstate trading of emissions allowances would be allowed only to the extent that the total number of emissions allowances used within a particular state did not exceed the state s budgeted allowances plus a variability limit intended to account for the variability of emissions due to changes in demand for electricity, timing of maintenance activities and unit outages. If total emissions allowances used within a state in a year exceed the annual budget plus the variability limit, then owners of generating facilities in that state that are deemed responsible for the state s exceedance would be required to surrender additional allowances. The two alternatives on which the EPA is seeking comment would further restrict trading. Under the first alternative, only intrastate trading of allowances would be allowed. The second alternative would establish an emissions limit for each generating facility, with some averaging allowed. Finally, the EPA has also stated that it may issue a subsequent, more stringent rule if the EPA concludes that recent or planned revisions to the particulate matter and ozone NAAQS make necessary more stringent limits on SO_2 and NOx emissions from electric generating facilities. We continue to monitor developments related to the EPA s proposed alternatives issued on July 6, 2010 to replace the existing CAIR rule.

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Virginia CAIR Implementation. In April 2006, Virginia enacted legislation that, among other things, granted the Virginia State Air Pollution Control Board the discretion to prohibit electric generating facilities located in a non-attainment area from purchasing SO2 and NOx allowances to achieve compliance under the EPA s CAIR. In the fourth quarter of 2007, the Virginia State Air Pollution Control Board approved regulations that it interpreted as prohibiting the acquisition in any manner of SO2 and NOx allowances by facilities in non-attainment areas to satisfy the requirements of the CAIR as implemented by Virginia. Mirant Potomac River s generating facility is located in a non-attainment area for ozone. Thus, this Virginia regulation effectively capped the Potomac River generating facility s SO2 and NOx emissions at amounts equal to the allowances allocated to the facility, which constrained the facility s operations. Mirant Potomac River challenged the legality of the regulations regarding the trading of NOx allowances in Virginia state court. On June 23, 2009, the Court of Appeals of Virginia issued an opinion concluding that the Virginia State Air Pollution Control Board exceeded its statutory authority. The Virginia State Air Pollution Control Board petitioned the Virginia Supreme Court to review the decision by the Virginia Court of Appeals, and the Virginia Supreme Court denied that request on October 15, 2009. In January 2010, the Virginia DEQ informed Mirant Potomac River that in light of the decision of the Virginia Court of Appeals vacating Virginia s rules restricting trading, the Virginia DEQ had determined that issuing a state operating permit to limit NOx emissions during the Ozone Season was warranted. In July 2010, the Virginia DEQ issued a permit that limits NOx emissions from Mirant Potomac River s generating facility to 890 tons during the Ozone Season that the Virginia DEQ asserts is effective for the 2010 Ozone Season. We think that at current market prices the new limit on NOx emissions during the Ozone Season will not have a material effect upon our results of operations, financial position or cash flows.

EPA Regulations Regarding Coal Combustion Byproducts. In June 2010, the EPA proposed two alternatives for regulating byproducts of coal combustion (e.g., ash and gypsum) under the federal Resource Conservation and Recovery Act of 1976. Under the first proposal, these byproducts would be regulated as solid wastes. Under the second proposal, these byproducts would be regulated as special wastes in a manner similar to the regulation of hazardous waste with an exception for beneficial reuse of these byproducts. The second alternative would impose significantly more stringent requirements on and increase materially the cost of disposal of coal combustion byproducts. The EPA expects to finalize this rule in 2011.

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Critical Accounting Estimates

The sections below contain updates to our summary of critical accounting estimates included under Item 7, *Management s Discussion and Analysis of Results of Operations and Financial Condition*, in our 2009 Annual Report on Form 10-K.

Revenue Recognition and Accounting for Energy Trading and Marketing Activities

Nature of Estimates Required. We utilize two comprehensive accounting models, an accrual model and a fair value model, in reporting our results of operations and financial position. We determine the appropriate model for our operations based on applicable accounting standards.

The accrual model is used to account for our revenues from the sale of energy, capacity and ancillary services. We recognize revenue when it has been earned and collection is probable as a result of electricity delivered or capacity available to customers pursuant to contractual commitments that specify volume, price and delivery requirements. Sales of energy are based on economic dispatch, or they may be as-ordered by an ISO or RTO, based on member participation agreements, but without an underlying contractual commitment. ISO and RTO revenues and revenues for sales of energy based on economic dispatch are recorded on the basis of MWh delivered, at the relevant day-ahead or real-time prices.

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

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

Key Assumptions and Approach Used. Determining the fair value of our derivatives is based largely on observable quoted prices from exchanges and independent brokers in active markets. We think that these prices represent the best available information for valuation purposes. For most delivery locations and tenors where we have positions, we receive multiple independent broker price quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of our derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for our assets and ask prices for liabilities. If no active market exists, we estimate the fair value of certain derivative financial instruments using price extrapolation, interpolation and other quantitative methods. We have not identified any distressed market conditions that would alter our valuation techniques at June 30, 2010. Fair value estimates involve uncertainties and matters of significant judgment. Our techniques for fair value estimation include assumptions for market prices, correlation and volatility. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. Note B to our unaudited condensed consolidated financial statements contained elsewhere in this report explains the fair value hierarchy. Our assets and liabilities classified as Level 3 in the fair value hierarchy represent approximately 3% of our total assets and 8% of our total liabilities measured at fair value at June 30, 2010.

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

Effect if Different Assumptions Used. The amounts recorded as revenue or cost of fuel, electricity and other products change as estimates are revised to reflect actual results and changes in market conditions or other factors, many of which are beyond our control. Because we use derivative financial instruments and have not elected cash flow or fair value hedge accounting, certain components of our financial statements, including gross margin, operating income and balance sheet ratios, are at times volatile and subject to fluctuations in value primarily as a result of changes in forward energy and fuel prices. Significant negative changes in fair value could require us to post additional collateral either in the form of cash or letters of credit. Because the fair value measurements of our material assets and liabilities are based on observable market information, there is not a significant range of values around the fair value estimate. For our derivative financial instruments that are measured at fair value using quantitative pricing models, a significant change in estimate could affect our results of operations and cash flows at the time contracts are ultimately settled. The estimated fair value of our derivative contract assets and liabilities was a net asset of $714 million at June 30, 2010. A 10% change in electricity and fuel prices would result in approximately a $180 million change in the fair value of our net asset at June 30, 2010. See Item 3, Quantitative and Qualitative Disclosures About Market Risk for further sensitivities in our assumptions used to calculate fair value. See Note B to our unaudited condensed consolidated financial statements contained elsewhere in this report for further information on derivative financial instruments related to energy trading and marketing activities.

Estimated Useful Lives

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

Key Assumptions and Approach Used. Estimated useful lives are the mechanism by which we allocate the cost of long-lived assets over the asset s service period. We perform depreciation studies periodically to update changes in estimated useful lives. The actual useful life of an asset could be affected by changes in estimated or actual commodity prices, environmental regulations, various legal factors, competitive forces and our liquidity and ability to sustain required maintenance expenditures and satisfy asset retirement obligations. We use composite depreciation for groups of similar assets and establish an average useful life for each group of related assets. In accordance with the accounting guidance related to evaluating long-lived assets for impairment, we cease depreciation on long-lived assets classified as held for sale. Also, we may revise the remaining useful life of an asset held and used subject to impairment testing.

We completed a depreciation study in the first quarter of 2010 that resulted in a change to the estimated useful lives of our long-lived assets. The change in useful lives resulted in a decrease of approximately $1 million and $2 million in depreciation and amortization expense for the three and six months ended June 30, 2010, respectively, and an increase of $0.01 and $0.01 in basic and diluted earnings per share for the three and six months ended June 30, 2010, respectively. In addition, the change in useful lives also resulted in an increase of $9 million in asset retirement obligations and a corresponding increase of $9 million in property, plant and equipment, net at June 30, 2010.

Effect if Different Assumptions Used. The determination of estimated useful lives is dependent on subjective factors such as expected market conditions, commodity prices and anticipated capital expenditures. Since composite depreciation rates are used, the actual useful life of a particular asset may differ materially from the useful life estimated for the related group of assets.

Asset Impairments

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

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

The prices for power and natural gas remain low compared to several years ago. The energy gross margin from our baseload coal units is negatively affected by these price levels. Additionally, the current economic recession and various demand-response programs have resulted in a decrease in the forecasted gross margin of our generating facilities. On an ongoing basis, we evaluate our long-lived assets for indications of impairment; however, given the remaining useful lives for many of our generating facilities, the total undiscounted cash flows for these generating facilities are more significantly affected by the long-term view of supply and demand than by the short term fluctuations in energy prices and demand. As such, we typically do not consider short term decreases in either energy prices or demand to cause an impairment evaluation.

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

Mirant Mid-Atlantic Our Dickerson generating facility is located in Montgomery County, Maryland. On May 19, 2010, the Montgomery County Council passed a law that imposes a levy on major emitters of CO2 in Montgomery County of $5 per ton of CO2 emitted. The law defines a major emitter of CO2 in Montgomery County to be a stationary source emitting 1 million tons or more annually of CO2. The Dickerson generating facility would fall within the definition of a major emitter, and is currently the only facility in Montgomery County that would meet the criteria to be a major emitter. We estimate that the law will impose an additional $10 million to $15 million per year in levies owed to Montgomery County. We have challenged the legality of the law, but cannot predict the outcome of any such challenge. As a result of Montgomery County enacting the levy, we reviewed the Dickerson generating facility for impairment in the second quarter.

As a result of the impairment analysis, we determined that no impairment charge was required as the scenario-weighted undiscounted cash flows exceeded the carrying value. Our estimate of future cash flows related to the Dickerson generating facility involved considering scenarios related to the Montgomery County levy. The scenarios relate to the success of the legal challenges to the law.

Our assessment of the Dickerson generating facility in the second quarter of 2010 included assumptions about the following:

- electricity, fuel and emissions prices;
- capacity payments under the RPM provisions of PJM s tariff;
- costs related to the Montgomery County CO2 emissions levy;
- costs of CO2 allowances under a potential federal cap-and-trade program;
- timing of announced transmission projects;
- timing and extent of generating capacity additions and retirements; and
- future capital expenditure requirements for the generating facility.

Our assumptions related to future electricity and fuel prices were based on observable market prices to the extent available and long-term prices derived from proprietary fundamental market modeling. The long-term capacity prices were based on the assumption that the PJM RPM capacity market would continue consistent with the current structure, with expected increases in revenue as a result of declines in reserve margins for periods beyond those for which auctions have already been completed. The total CO2 costs under the levy were determined by applying the cost of CO2 emissions to the expected generation forecasts. We also assumed that a federal CO2 cap-and-trade program would be instituted later this decade which would supplant all pre-existing CO2 programs, including the Montgomery County levy. There are several transmission projects currently planned in the Mid-Atlantic region, including the Trans-Allegheny Interstate Line (TrAIL), Mid-Atlantic Power Pathway transmission line (MAPP) and the Potomac-Appalachian transmission line (PATH). The assumptions regarding the timing of these projects were based on the current status of permitting and construction of each project. The assumptions regarding electricity demand are based on forecasts from PJM and assumptions for generating capacity additions and retirements consider publicly-announced projects, including renewable sources of electricity and additions of nuclear capacity. Capital expenditures include the remaining contract retention payments for the remainder of 2010 for the completion of the Maryland Healthy Air Act pollution control equipment.

The estimates and assumptions used in the impairment analysis of the Dickerson generating facility are subject to a high degree of uncertainty, and changes in these assumptions could result in future impairment losses. The scenario-weighted undiscounted cash flows exceeded the carrying value of the Dickerson generating facility by less than 5%. A decrease in projected electricity prices or an increase in coal prices would decrease the future cash flows of the Dickerson generating facility. Additionally, changes to the structure of the PJM RPM capacity market could negatively affect the future capacity prices the facility will earn. The assumptions include the development of a potential federal cap-and-trade program for CO2 emissions. If we are not compensated for the costs of complying with a federal CO2 program through allocated CO2 allowances, increased electricity and capacity prices or decreased coal prices, the cash flows of the Dickerson generating facility would be negatively affected. In addition, if pre-existing CO2 emission programs such as the Montgomery County levy are allowed to remain in effect under a federal CO2 program, the cash flows of the Dickerson generating facility would be negatively affected. If the planned transmission projects are completed earlier than assumed, this could negatively affect the cash flows of the facility. Also, changes in assumptions regarding generating capacity additions and retirements in the PJM region could affect the cash flows, depending on the timing and extent of additions and retirements. The assumptions include only those capital expenditures needed to keep the plant operational through its estimated remaining useful life. However, changes in laws or regulations could require additional capital investments beyond amounts forecasted to keep the plant operational.

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

For purposes of impairment testing, a long-lived asset or assets must be grouped at the lowest level of independent identifiable cash flows. The Dickerson generating facility was determined to be its own group, which includes the leasehold improvements for the leased generating units at the facility. The carrying value of the Dickerson generating facility represented approximately 18% of our total property, plant and equipment, net at June 30, 2010.

Mirant Bowline In April 2010, the NYISO issued its annual peak load and energy forecast, which we have evaluated and utilized to develop cash flow projections for our Bowline generating facility. Incorporating these assumptions, along with the current status related to the property tax proceedings, our undiscounted cash flows significantly exceed the carrying value of the long-lived assets. The carrying value of the Bowline generating facility represented approximately 4% of our total property, plant and equipment, net at June 30, 2010.

Emissions Allowances In July 2010, the EPA issued a proposed replacement for the CAIR. The market prices for SO2 and NOx emissions allowances continued to decline in the second quarter and declined further as a result of the proposed rule. Our historical accounting policy has been to include emissions allowances in our asset groupings when evaluating long-lived assets for impairment. However, to the extent the final EPA rule significantly modifies or ends the current cap-and-trade program, we may evaluate whether our SO2 and NOx emissions allowances included in property, plant and equipment and intangible assets should be evaluated separately from the underlying generating facilities. The carrying value of the SO2 and NOx emissions allowances included in property, plant and equipment and intangible assets at June 30, 2010 was approximately $190 million. See Environmental and Regulatory Matters earlier in this section for further information on the EPA s proposed replacement of the CAIR.

Litigation

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

See Note K to our unaudited condensed consolidated financial statements contained elsewhere in this report for further information related to our legal proceedings.

Recently Adopted Accounting Guidance

See Note A to our unaudited condensed consolidated financial statements contained elsewhere in this report for further information related to our recently adopted accounting guidance.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

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 $714 million and $898 million at June 30, 2010 and 2009, respectively. The following tables provide a summary of the factors affecting the change in fair value of the derivative contract asset and liability accounts for the six months ended June 30, 2010 and 2009 (in millions):

	Commodity Contracts		
	Asset Management	Trading Activities	Total
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]	36	44	80
Roll off of previous values[2]	(177)	(39)	(216)
Purchases, issuances and settlements[3]	150	(2)	148
Fair value of portfolio of assets and liabilities at June 30, 2010	$ 710	$ 4	$ 714

	Commodity Contracts		
	Asset Management	Trading Activities	Total
Fair value of portfolio of assets and liabilities at January 1, 2009	$ 549	$ 106	$ 655
Gains (losses) recognized in the period, net:			
New contracts and other changes in fair value[1]	217	(80)	137
Roll off of previous values[2]	(197)	(54)	(251)
Purchases, issuances and settlements[3]	283	74	357
Fair value of portfolio of assets and liabilities at June 30, 2009	$ 852	$ 46	$ 898

[1] The fair value, as of the end of each quarterly reporting period, of contracts entered into during each quarterly reporting period and the gains or losses attributable to contracts that existed as of the beginning of each quarterly reporting period and were still held at the end of each quarterly reporting period.
[2] The fair value, as of the beginning of each quarterly reporting period, of contracts that settled during each quarterly reporting period.
[3] Denotes cash settlements during each quarterly reporting period of contracts that existed at the beginning of each quarterly reporting period.

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

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

Counterparty Credit Risk

The valuation of our derivative contract assets is affected by the default risk of the counterparties with which we transact. We recognized a reserve, which is reflected as a reduction of our derivative contract assets, related to counterparty credit risk of $36 million and $13 million at June 30, 2010 and December 31, 2009, respectively.

In accordance with the fair value measurements accounting guidance, we calculate the credit reserve through consideration of observable market inputs, when available. Our non-collateralized power hedges entered into by Mirant Mid-Atlantic with our major trading partners, which represent 61% of our net notional power position at June 30, 2010, are senior unsecured obligations of Mirant 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. We calculate the credit reserve for our non-collateralized power hedges entered into by Mirant Mid-Atlantic using 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. Potential loss exposure is calculated as our current exposure plus a calculated VaR over the remaining life of the contracts. We applied a similar approach to calculate the fair value of our coal contracts included in derivative contract assets and liabilities in the unaudited condensed consolidated balance sheets and which 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. We do not, however, transact in credit default swaps or any other credit derivative. An increase of 10% in the spread of credit default swaps of our major trading partners for our non-collateralized power hedges entered into by Mirant Mid-Atlantic would result in an increase of $3 million in our credit reserve as of June 30, 2010. An increase of 10% in the spread of credit default swaps of our coal suppliers would result in an increase of less than $1 million in our credit reserve for our coal agreements included in derivative contract assets and liabilities in the unaudited condensed consolidated balance sheet as of June 30, 2010.

We have historically calculated the credit reserve for the remainder of our portfolio considering our current exposure, net of the effect of credit enhancements, and potential loss exposure from the financial commitments in our risk management portfolio, and applied historical default probabilities using current credit ratings of our counterparties. In the fourth quarter of 2009, we changed our methodology to calculate the credit reserve for the remainder of our portfolio to also use 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. The change in credit reserve methodology did not have a material effect on the fair value of our derivative contract assets and liabilities for the remainder of the portfolio because the default risk is generally offset by cash collateral or other credit enhancements. An increase in counterparty credit risk could affect the ability of our counterparties to deliver on their obligations to us. As a result, we may require our counterparties to post additional collateral or provide other credit enhancements. An increase of 10% in the spread of credit default swaps of our trading partners for the remainder of our portfolio would result in an immaterial increase in our credit reserve as of June 30, 2010.

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

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We also monitor counterparty credit concentration risk on both an individual basis and a group counterparty basis. See Note B to our unaudited condensed consolidated financial statements contained elsewhere in this report for further discussion of our counterparty credit concentration risk.

Mirant Credit Risk

In valuing our derivative contract liabilities, we apply a valuation adjustment for our non-performance, which is based on the probability of our default. Historically, we determined this non-performance adjustment value by multiplying our liability exposure, including outstanding balances for realized transactions, unrealized transactions and the effect of credit enhancements, by the one year probability of our default based on our current credit rating. The one year probability of default rate considers the tenor of our portfolio and the correlation of default between counterparties within our industry. In the fourth quarter of 2009, we changed our methodology to incorporate published spreads on our credit default swaps, where available, or proxies based upon published spreads. An increase of 10% in the spread of our credit default swap rate would have an immaterial effect on our unaudited condensed consolidated statement of operations for the six months ended June 30, 2010.

Broker Quotes

In determining the fair value of our derivative contract assets and liabilities, we use third-party market pricing where available. We consider active markets to be those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Note B to our unaudited condensed consolidated financial statements contained elsewhere in this report explains the fair value hierarchy. Our transactions in Level 1 of the fair value hierarchy primarily consist of natural gas and crude oil futures traded on the NYMEX and swaps cleared against NYMEX prices. For these transactions, we use the unadjusted published settled prices on the valuation date. Our transactions in Level 2 of the fair value hierarchy primarily include non-exchange-traded derivatives such as OTC forwards, swaps and options. We value these transactions using quotes from independent brokers or other widely-accepted valuation methodologies. Transactions are classified in Level 2 if substantially all (greater than 90%) of the fair value can be corroborated using observable market inputs such as transactable broker quotes. In accordance with the exit price objective under the fair value measurements accounting guidance, the fair value of our derivative contract assets and liabilities is determined based on the net underlying position of the recorded derivative contract assets and liabilities using bid prices for our assets and ask prices for liabilities. The quotes that we obtain from brokers are non-binding in nature, but are from brokers that typically transact in the market being quoted and are based on their knowledge of market transactions on the valuation date. We typically obtain multiple broker quotes on the valuation date for each delivery location that extend for the tenor of our underlying contracts. The number of quotes that we can obtain depends on the relative liquidity of the delivery location on the valuation date. If multiple broker quotes are received for a contract, we use an average of the quoted bid or ask prices. If only one broker quote is received for a delivery location and it cannot be validated through other external sources, we will assign the quote to a lower level within the fair value hierarchy. In some instances, we may combine broker quotes for a liquid delivery hub with broker quotes for the price spread between the liquid delivery hub and the delivery location under the contract. We also may apply interpolation techniques to value monthly strips if broker quotes are only available on a seasonal or annual basis. We perform validation procedures on the broker quotes at least on a monthly basis. The validation procedures include reviewing the quotes for accuracy and comparing them to our internal price curves. In certain instances, we may discard a broker quote if it is a clear outlier and multiple other quotes are obtained. At June 30, 2010, we obtained broker quotes for 100% of our delivery locations classified in Level 2 of the fair value hierarchy.

Inactive markets are considered to be those markets with few transactions, noncurrent pricing or prices that vary over time or among market makers. Our transactions in Level 3 of the fair value hierarchy may involve transactions whereby observable market data, such as broker quotes, are not available for substantially all of the tenor of the contract or we are only able to obtain indicative broker quotes that cannot be corroborated by observable market data. In such cases, we may apply valuation techniques such as extrapolation to determine fair value. Proprietary models may also be used to determine the fair value of certain of our derivative contract assets and liabilities that may be structured or otherwise tailored. The degree of estimation increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points. Our techniques for fair value estimation include assumptions for market prices, correlation and volatility. At June 30, 2010, our assets and liabilities classified as Level 3 in the fair value hierarchy represented approximately 3% of our total assets and 8% of our total liabilities measured at fair value. See Note B to our unaudited condensed consolidated financial statements contained elsewhere in this report for further explanation of the fair value hierarchy.

Interest Rate Risk

Fair Value Measurement

We are also subject to interest rate risk when determining the fair value of our derivative contract assets and liabilities. The nominal value of our derivative contract assets and liabilities is also discounted to account for time value using a LIBOR forward interest rate curve based on the tenor of our transactions. An increase of 100 basis points in the average LIBOR rate would result in a decrease of $25 million to our derivative contract assets and a decrease of $12 million to our derivative contract liabilities at June 30, 2010.

Debt

Our debt that is subject to variable interest rates consists of the Mirant North America senior secured term loan and senior secured revolving credit facility. If both were fully drawn, the amount subject to variable interest rates would be approximately $1.1 billion and a 1% per annum increase in the average market rate would result in an increase in our annual interest expense of approximately $11 million.

Coal Agreement Risk

Our coal supply comes primarily from the Central Appalachian and Northern 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 strategic suppliers under contracts with terms of varying lengths, some of which extend to 2013. We had exposure to four counterparties at June 30, 2010, and exposure to five counterparties at December 31, 2009, that each represented an exposure of more than 10% of our total coal commitments, by volume, and in aggregate represented approximately 74% and 85% of our total coal commitments at June 30, 2010 and December 31, 2009, 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, a number of the coal suppliers do not currently have an investment grade credit rating and, accordingly, we may have limited recourse to collect damages in the event of default by a supplier. 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 B to our unaudited condensed consolidated financial statements contained elsewhere in this report for further explanation of these agreements and our credit concentration tables.

Certain of our coal contracts are not required to be recorded at fair value under the accounting guidance for derivative financial instruments. As such, these contracts are not included in derivative contract assets and liabilities in the accompanying unaudited condensed consolidated balance sheets. As of June 30, 2010, the estimated net fair value of these coal agreements was approximately $13 million.

For a further discussion of market risks, our risk management policy and our use of VaR to measure some of these risks, see Item 7A, *Quantitative and Qualitative Disclosures About Market Risk* in our 2009 Annual Report on Form 10-K.

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 June 30, 2010. Based upon this assessment, our management concluded that, as of June 30, 2010, the design and operation of these disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

There have been no changes in Mirant s internal control over financial reporting that have occurred during the quarter ended June 30, 2010, that have materially affected, or are reasonably likely to materially affect, such internal control over financial reporting.

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PART II

Item 1. Legal Proceedings

See Note K to our unaudited condensed consolidated financial statements contained elsewhere in this report for discussion of the material legal proceedings to which we are a party.

Item 1A. Risk Factors

The following are factors that could affect our future performance. Further information concerning the proposed merger with RRI Energy was included in a joint proxy statement/prospectus contained in the registration statement on Form S-4 filed by RRI Energy with the SEC on May 28, 2010, and amended on July 6, 2010.

Risks related to the proposed merger with RRI Energy

We may be unable to obtain the approvals required to complete the merger with RRI Energy or, in order to do so, the combined company may be required to comply with material restrictions or conditions.

On April 11, 2010, we announced the execution of a Merger Agreement with RRI Energy. Before the merger may be completed, both Mirant and RRI Energy will need to obtain stockholder approval in connection with the proposed transaction. In addition, various filings must be made with FERC and various regulatory, antitrust and other authorities in the United States. These governmental authorities may impose conditions on the completion, or require changes to the terms, of the merger, including restrictions or conditions on the business, operations or financial performance of the combined company following completion of the merger. These conditions or changes could have the effect of delaying completion of the merger or imposing additional costs on or limiting the revenues of the combined company following the merger, which could have a material adverse effect on the financial results of the combined company and/or cause either Mirant or RRI Energy to abandon the merger.

In addition, several putative class actions have been brought on behalf of holders of Mirant common stock seeking to enjoin the merger or other alternative relief. If these actions or similar actions that may be brought are successful, the merger could be delayed or prevented. See Note K to our unaudited condensed consolidated financial statements contained elsewhere in the report for further information on pending litigation related to the merger.

If we are unable to complete the merger, we still will incur and will remain liable for significant transaction costs, including legal, accounting, filing, printing and other costs relating to the merger. Also, depending upon the reasons for not completing the merger, including whether we have received or entered into a competing takeover proposal, we may be required to pay RRI Energy a termination fee of either $37.15 million or $57.78 million.

If completed, our merger with RRI Energy may not achieve its intended results.

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

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

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

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

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

In addition, we are restricted under the Merger Agreement, without RRI Energy s consent, from making certain acquisitions and taking other specified actions until the merger occurs or the Merger Agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the Merger Agreement.

Risks Related to the Operation of our Business

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

We sell capacity, energy and ancillary services from our generating facilities into competitive power markets on a short-term fixed price basis or through power sales agreements. Since mid-2007, our revenues from selling capacity have become a significant part of our overall revenues. Except for our Potrero generating facility, we are not guaranteed recovery of our costs or any return on our capital investments through mandated rates. The market for wholesale electric energy and energy services reflects various market conditions beyond our control, including the balance of supply and demand, our competitors marginal and long-run costs of production, and the effect of market regulation. The price for which we can sell our output may fluctuate on a day-to-day basis, and our ability to transact may be affected by the overall liquidity in the markets in which we operate. The markets in which we compete remain subject to one or more forms of regulation that limit our ability to raise prices during periods of shortage to the degree that would occur in a fully deregulated market and may thereby limit our ability to recover costs and an adequate return on our investment. Our revenues and results of operations are influenced by factors that are beyond our control, including:

- the failure of market regulators to develop and maintain efficient mechanisms to compensate merchant generators for the value of providing capacity needed to meet demand;

- actions by regulators, ISOs, RTOs and other bodies that may artificially modify supply and demand levels and prevent capacity and energy prices from rising to the level necessary for recovery of our costs, our investment and an adequate return on our investment;

- legal and political challenges to the rules used to calculate capacity payments in the markets in which we operate;

- the ability of wholesale purchasers of power to make timely payment for energy or capacity, which may be adversely affected by factors such as retail rate caps, refusals by regulators to allow utilities to recover fully their wholesale power costs and investments through rates, catastrophic losses and losses from investments by utilities in unregulated businesses;

- increases in prevailing market prices for fuel oil, coal, natural gas and emissions allowances that may not be reflected in prices we receive for sales of energy;

- increases in electricity supply as a result of actions of our current competitors or new market entrants, including the development of new generating facilities or alternative energy sources that may be able to produce electricity less expensively than our generating facilities and improvements in transmission that allow additional supply to reach our markets;

- increases in credit standards, margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts that are expected, including additional collateral costs associated with OTC hedging activities as a result of the recently enacted OTC regulations and the Dodd-Frank Act;

- decreases in energy consumption resulting from demand-side management programs such as automated demand response, which may alter the amount and timing of consumer energy use;

- the competitive advantages of certain competitors, including continued operation of older power plants in strategic locations after recovery of historic capital costs from ratepayers;

- existing or future regulation of our markets by the FERC, ISOs and RTOs, including any price limitations and other mechanisms to address some of the price volatility or illiquidity in these markets or the physical stability of the system;

- regulatory policies of state agencies that affect the willingness of our customers to enter into long-term contracts generally, and contracts for capacity in particular;

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

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

- seasonal fluctuations in weather, in particular abnormal weather conditions.

In addition, unlike most other commodities, electric energy can only be stored on a very limited basis and generally must be produced at the time of use. As a result, the wholesale power markets are subject to substantial price fluctuations over relatively short periods of time and can be unpredictable.

Because of the current market design in California, our existing generating facilities may have a limited life unless we make significant capital expenditures to increase their commercial and environmental performance.

Our existing generating facilities in California depend almost entirely on payments in support of system reliability. The energy market, as currently constituted, will not justify the capital

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expenditures necessary to repower or reconstruct our facilities to make them commercially viable in a merchant market. If a commercially reasonable capacity market were to be instituted by the CAISO or we could obtain a contract with a creditworthy buyer, it is possible that we could justify investing the necessary capital to repower or reconstruct our facilities. Absent that, our existing generating facilities will be commercially viable only as long as they are necessary for reliability. We plan to shut down the Contra Costa generating facility in April 2013 and the Potrero generating facility when it is no longer needed for reliability as determined by the CAISO. The CAISO will not determine which units of the Potrero generating facility are required to operate in 2011 for reliability purposes until the fall of 2010. If none of the units of the Potrero generating facility will be required to operate for reliability purposes after 2010, then all of the units will close by the end of 2010.

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

In 2009, Mirant Marsh Landing entered into a ten-year PPA with PG&E for 760 MW of natural gas-fired peaking generation to be constructed adjacent to our Contra Costa generating facility near Antioch, California. Under the terms of the PPA, Mirant Marsh Landing bears the risks of (i) obtaining the permits and approvals necessary for construction and operation of the generating facility, (ii) securing the necessary financing for construction of the generating facility and (iii) completing the construction of the generating facility by May 2013. The process for obtaining governmental permits and approvals is complicated and lengthy and is subject to significant uncertainties. Mirant Marsh Landing has posted letters of credit of approximately $12 million to secure its obligations under the PPA, which amount is expected to increase in the third quarter to approximately $80 million as a result of the approval of the PPA by the CPUC on July 29, 2010. Mirant Marsh Landing has also posted a surety bond of $4 million to secure obligations for transmission system improvements. Although we have attempted to minimize the financial risks in the development of the Marsh Landing generating facility, in the event that we are unsuccessful in securing the required permits, approvals and financing necessary to construct the facility, we may not be able to recover our investment in the development of the project. If we do not complete the construction of the Marsh Landing generating facility by May 2013, our return on the project may be lower than expected. Should the facility not perform as required under the terms of the PPA, PG&E may have the right to terminate the PPA. As there is currently no wholesale capacity market in California, if PG&E were to terminate the PPA, our return on the project might be materially lower than expected.

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

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

We enter into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase most of our coal from a small number of strategic suppliers under contracts with terms of varying lengths, some of which extend to 2013. 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, a number of the coal suppliers do not currently have an investment grade credit rating and, accordingly, we may have limited recourse to collect damages in the event of default by a supplier. 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.

For our oil-fired generating facilities, we typically purchase fuel from a limited number of suppliers under contracts with terms of varying lengths. If our oil suppliers do not perform in accordance with the agreements, we may have to procure oil in the market to meet our needs, or power in the market to meet our obligations.

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

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

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

curtailment of operations because of transmission constraints;

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

implementation of unproven technologies in connection with environmental improvements; and

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

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

Our operating results are subject to quarterly and seasonal fluctuations.

Our operating results have fluctuated in the past and are likely to continue to do so in the future as a result of a number of factors, including seasonal variations in demand and fuel prices.

Our generating facilities are located in a few geographic markets, resulting in concentrated exposure to the Mid-Atlantic market.

Our generating facilities are located in California, Maryland, Massachusetts, New York and Virginia. For the three and six months ended June 30, 2010 and 2009, we earned a significant portion of our operating revenue and gross margin from the PJM market, where our Mid-Atlantic generating facilities are located. Having our generating facilities in a few geographic markets results in our concentrated exposure to those markets, especially PJM.

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

As of December 31, 2009, we had approximately $2.7 billion of federal NOL carry forwards. Our ability to deduct the NOL carry forwards against future taxable income could be substantially limited if we experience an ownership change, as defined in Section (§) 382 of the Internal Revenue Code of 1986, at or near our recent stock price levels. In general, an ownership change would occur if certain shifts in ownership of the Company s stock exceed 50 percentage points measured over a specified period of time. Given §382 s broad definition, an ownership change could be the unintended consequence of otherwise normal market trading in the Company s stock that is outside our control. On March 26, 2009, we adopted a stockholder rights plan (the Stockholder Rights Plan) to reduce the likelihood of such an unintended ownership change occurring. However, there can be no assurance that the Stockholder Rights Plan will prevent such an ownership change.

Under the Stockholder Rights Plan, when a person or group has obtained beneficial ownership of 4.9% or more of our common stock, or an existing holder with greater than 4.9% ownership acquires more shares representing at least an additional 0.2% of our common stock, there would be a triggering event causing potential significant dilution in the economic interest and voting power of such person or group. Such triggering event would also occur if an existing holder with greater than 4.9% ownership but less than 5.0% ownership acquires more shares that would result in such stockholder obtaining beneficial ownership of 5.0% or more of our common stock. The Board of Directors has the discretion to exempt an acquisition of common stock from the provisions of the Stockholder Rights Plan if it determines the acquisition will not jeopardize tax benefits or is otherwise in our best interests.

On February 26, 2010, Mirant announced that the Board of Directors had extended the Stockholder Rights Plan and on April 28, 2010, the Company entered into a further amendment to the Stockholders Rights Plan (the Second Amendment) with Mellon Investor Services LLC, as Rights Agent (the Rights Agent). The Second Amendment reduces the maximum term of the Stockholders Rights Plan from ten years to three years. Under the terms of the Stockholder Rights Plan (prior to the Second Amendment), the rights (as defined in the Stockholder Rights Plan) would have expired on the earliest of (i) February 25, 2020 (the Fixed Date), (ii) the time at which the rights are redeemed, (iii) the time at which the rights are exchanged, (iv) the repeal of §382 or any successor statute, or any other change, if the Board of Directors determines that the Stockholder Rights Plan is no longer necessary for the preservation of tax benefits, (v) the beginning of a taxable year of the Company for which the Board of Directors determines that no tax benefits may be carried forward and no built-in losses may be recognized, (vi) February 25, 2011 if stockholder approval has not been obtained, or (vii) a determination by the Board of Directors, prior to the time any person or group becomes an Acquiring Person (as defined in the Stockholder Rights Plan), that the Stockholder Rights Plan and the rights are no longer in the best interests of the Company and its stockholders. The Second Amendment amends the Fixed Date to February 25, 2013. On May 6, 2010, the Company s stockholders approved the Stockholder Rights Plan at the Company s 2010 Annual Meeting of Stockholders.

Mirant has previously announced its intention to enter into a merger with RRI Energy Inc. In connection with entering into the Merger Agreement, we took such actions necessary to render the Stockholder Rights Plan inapplicable to the merger transaction with RRI Energy.

Provided neither has experienced an ownership change between December 31, 2009 and the closing date of the merger, each of Mirant and RRI Energy is expected separately to experience an ownership change on the merger date as a consequence of the merger. Immediately following the merger, Mirant and RRI Energy will be members of the same consolidated federal income tax group. The ability of this consolidated tax group to deduct pre-merger NOL carry forwards of Mirant and RRI Energy against the post merger taxable income of the group will be substantially limited as a result of these ownership changes.

If Mirant were to experience an ownership change after December 31, 2009 but prior to the closing date of the merger and the merger were subsequently consummated, Mirant would be subject to the limitation on its NOLs determined as of the date of such ownership change and not as of the date of the merger. This limitation would apply to Mirant s use of its NOLs against Mirant s taxable income up to the date of the merger, and to the use of Mirant s NOLs against the post merger taxable income of the consolidated federal income tax group resulting from the merger. The effect of such an ownership change has not been quantified.

If Mirant were to experience an ownership change after December 31, 2009 but prior to the closing date of the merger and the merger were not subsequently consummated, Mirant would be subject to the limitation on its NOLs determined as of the date of such ownership change. This limitation would apply to Mirant s use of its NOLs against Mirant s taxable income from the date of such ownership change forward. In this case, our inability to utilize Mirant s NOL carry forwards at the rates at which they are currently available could result in the payment of cash taxes above the amounts currently estimated for future periods and have a negative effect on our future results of operations and financial position.

We compete to sell energy, capacity and ancillary services in the wholesale power markets against some competitors that enjoy competitive advantages, including the ability to recover fixed costs through rate-base mechanisms and a lower cost of capital.

Regulated utilities in the wholesale markets generally enjoy a lower cost of capital than we do and often are able to recover fixed costs through regulated retail rates, including, in many cases, the costs of generation, allowing them to build, buy and upgrade generating facilities without relying exclusively on market-clearing prices to recover their investments. The competitive advantages of such participants could adversely affect our ability to compete effectively and could have an adverse effect on the revenues generated by our facilities.

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

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

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

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

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

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

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

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

We are currently involved in significant litigation that, if decided adversely to us, could materially adversely affect our results of operations and profitability.

We are currently involved in various litigation matters which are described in more detail in our 2009 Annual Report on Form 10-K and in Note K to our unaudited condensed consolidated financial statements contained elsewhere in this Form 10-Q. We intend to defend vigorously against those claims that we are unable to settle, but the results of this litigation cannot be determined. Adverse outcomes for us in this litigation could require significant expenditures by us and could have a material adverse effect on our results of operations and profitability.

Risks Related to Economic and Financial Capital Market Conditions

Maintaining sufficient liquidity in our business for maintenance and operating expenditures, capital expenditures and collateral is crucial in order to mitigate the risk of future financial distress to us. Accordingly, we maintain a revolving credit facility to manage our expected liquidity needs and contingencies. If the lenders under such facility were unable to perform, it could have a material adverse effect on our results of operations. As a result, we are exposed to systemic risk of the financial markets and institutions and the risk of non-performance of the individual lenders under our revolving credit facility.

Maintaining sufficient liquidity in our business for maintenance and operating expenditures, capital expenditures and collateral is crucial in order to mitigate the risk of future financial distress to us. Accordingly, we maintain a revolving credit facility to manage our expected liquidity needs and contingencies as described in more detail in this Form 10-Q. If the lenders under such facility were unable to perform, it could have a material adverse effect on our results of operations. For example, in October 2008, Lehman Commercial Paper, Inc., a subsidiary of Lehman Brothers Holdings, Inc. and a lender under the senior secured revolving credit facility of our subsidiary, Mirant North America, filed for bankruptcy. As a result of the Lehman Commercial Paper, Inc. bankruptcy, the total availability under our senior secured revolving credit facility has effectively decreased from $800 million to $755 million. Although we do not expect that the Lehman Commercial Paper, Inc. bankruptcy will have a material adverse effect on Mirant, a credit crisis could negatively affect availability under the Mirant North America senior secured revolving credit facility if other lenders under such facility are forced to file for bankruptcy or are otherwise unable to perform their obligations. Absent significant non-performance of lenders under the existing Mirant North America senior secured revolving credit facility, we think that we have sufficient liquidity for future operations (including potential working capital requirements) and capital expenditures as discussed in Item 2. Management s Discussion and Analysis of Results of Operations and Financial Condition Liquidity and Capital Resources. However, in the event of significant non-performance of lenders under the existing Mirant North America senior secured revolving credit facility, or in the event that financial institutions are unwilling or unable to renew our existing revolving credit facility or enter into new revolving credit facilities, our ability to hedge our assets or engage in proprietary trading could be impaired.

Global financial institutions have been active participants in the energy and commodity markets, and we hedge economically a substantial portion of our Mid-Atlantic coal-fired baseload generation with such parties. As such financial institutions consolidate and operate under more restrictive capital constraints and regulations in response to the recent financial crisis, there could be less liquidity in the energy and commodity markets, which could have a negative effect on our ability to hedge and transact with creditworthy counterparties.

In recent years, global financial institutions have been active participants in the energy and commodity markets. We hedge economically a substantial portion of our Mid-Atlantic coal-fired baseload generation through OTC transactions. A majority of our hedges are financial swap transactions between Mirant 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. As such financial institutions consolidate and operate under more restrictive capital constraints and regulations in response to the recent financial crisis, there could be less liquidity in the energy and commodity markets, which could have a negative effect on our ability to hedge and transact with creditworthy counterparties.

Greater regulation of energy contracts, including the regulation of OTC derivative financial instruments, could materially affect our ability to hedge economically our generation by reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing the collateral costs associated with such activities.

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 legislative history of the Dodd-Frank Act, including a letter from Senators Dodd and Lincoln, provides strong evidence that market participants, such as Mirant, which utilize OTC derivative financial instruments to hedge commercial risks, are not to be subject to these clearing and other requirements, it is uncertain what the implementing regulations to be issued by the CFTC will provide. Greater regulation of OTC derivative financial instruments could materially affect our ability to hedge economically our generation by reducing liquidity in the energy and commodity markets, increasing hedge pricing through the imposition of capital requirements on our swap counterparties and, if we are required to clear such transactions on exchanges, by significantly increasing our requirements for cash collateral.

In addition to the Dodd-Frank Act, the CFTC has designated certain electricity contracts as significant price discovery contracts (SPDCs), including contracts that we trade on the Intercontinental Exchange Inc. based on CAISO and PJM West Hub locational marginal pricing. As a result of the SPDC designation, the contracts are subject to new more stringent requirements and could set a precedent for more contracts to be designated as SPDCs.

Further, the CFTC issued a notice of proposed rulemaking in which it proposed to adopt all-months-combined, single (non-spot) month and spot-month position limits for exchange-listed natural gas, crude oil, heating oil and gasoline futures and options contracts. We continue to monitor the rulemaking proceeding, but do not think that the limits as proposed would have a material effect on our business.

While we do not expect the Dodd-Frank Act and the proposals at the CFTC to have a material adverse effect on our business, a continuation of the trend of greater regulation of energy contracts, including more restrictive regulation of OTC derivative contracts, could materially affect our ability to hedge economically our generation by reducing liquidity in the energy and commodity markets and, if we are required to clear such transactions on exchanges or meet other requirements, by significantly increasing our requirements for cash collateral.

We are exposed to credit risk resulting from a loss that may occur from the failure of a counterparty to perform according to the terms of a contractual arrangement with us, particularly in connection with our non-collateralized power hedges entered into by Mirant Mid-Atlantic with financial institutions.

We are exposed to credit risk resulting from the possibility that a loss may occur from the failure of a counterparty to perform according to the terms of a contractual arrangement with us, particularly in connection with our non-collateralized power hedges entered into by Mirant Mid-Atlantic with our major trading partners, which represent 61% of our net notional power position at June 30, 2010. Such hedges are senior unsecured obligations of Mirant Mid-Atlantic and the counterparties, and do not require either party to post cash collateral for initial margin or for securing exposure as a result of changes in power or natural gas prices. Deterioration in the financial condition of our counterparties and any resulting failure to pay amounts owed to us or to perform obligations or services owed to us beyond collateral posted could have a negative effect on our business and financial condition.

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

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

Our use of derivative financial instruments in our asset management activities will not fully protect us from fluctuations in commodity prices, and our risk management policy cannot eliminate the risks associated with these activities.

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

Our asset management activities include natural gas derivative financial instruments that we use to hedge power prices for our baseload generation. The effectiveness of these hedges is dependent upon the correlation between power and natural gas prices in the markets where we operate. If those prices are not sufficiently correlated, our financial results and financial position could be adversely affected.

Additionally, we expect to have an open position in the market, within our established guidelines, resulting from the management of our portfolio. To the extent open positions exist, fluctuating commodity prices can affect our financial results and financial position, either favorably or unfavorably. Furthermore, the risk management procedures we have in place may not always be followed or may not always work as planned. However, we have designed a system of internal controls to prevent and/or detect unauthorized hedging and related activities, including our risk management policy. If any of our employees were able to engage in unauthorized hedging and related activities, it could result in significant penalties and financial losses. As a result of these and other factors, we cannot predict the outcome that risk management decisions may have on our business, operating results or financial position. Although management devotes considerable attention to these issues, their outcome is uncertain.

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

We engage in asset management activities to hedge economically our exposure to market risk with respect to: (1) electricity sales from our generating facilities; (2) fuel used by those facilities; and (3) emissions allowances. We generally attempt to balance our fixed-price purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative financial instruments. We also use derivative financial instruments with respect to our limited proprietary trading and fuel oil management activities, through which we attempt to achieve incremental returns by transacting where we have specific market expertise. Derivatives from our asset management, proprietary trading and fuel oil management activities are recorded on our balance sheet at fair value pursuant to the accounting guidance for derivative financial instruments. None of our derivatives recorded at fair value is designated as a hedge under this guidance, and changes in their fair values currently are recognized in earnings as unrealized gains or losses. As a result, our financial results including gross margin, operating income and balance sheet ratios will, at times, be volatile and subject to fluctuations in value primarily because of changes in forward electricity and fuel prices.

Risks Related to Governmental Regulation and Laws

Our business and activities are subject to extensive environmental requirements and could be adversely affected by such requirements, including future changes to them.

Our business is subject to extensive environmental regulations promulgated by federal, state and local authorities, which, among other things, restrict the discharge of pollutants into the air, water and soil, and also govern the use of water from adjacent waterways. Such laws and regulations frequently require us to obtain permits and remain in continuous compliance with the conditions established by those permits. To comply with these legal requirements and the terms of our permits, we must spend significant sums on environmental monitoring, pollution control equipment and emissions allowances. If we were to fail to comply with these requirements, we could be subject to civil or criminal liability, injunctive relief and the imposition of liens or fines. We may be required to shut down facilities (including ash sites) if we are unable to comply with the requirements, or if we determine the expenditures required to comply are uneconomic.

From time to time, we may not be able to obtain necessary environmental regulatory approvals. Such approvals could be delayed or subject to onerous conditions. If there is a delay in obtaining environmental regulatory approval or if onerous conditions are imposed, the operation of our generating facilities or ash sites or the sale of electricity to third parties could be prevented or become subject to additional costs. Such delays or onerous conditions could have a material adverse effect on our financial performance and condition. In addition, environmental laws, particularly with respect to air emissions, disposal of ash, wastewater discharge and cooling water systems, are generally becoming more stringent, which may require us to make additional facility upgrades or restrict our operations.

Increased public concern and growing political pressure related to global warming have resulted in significant increases in the regulation of greenhouse gases, including CO2, at the state level. Future local, state and federal regulation of greenhouse gases is likely to create substantial environmental costs for us in the form of fees or taxes or purchases of emissions allowances and/or new equipment. For example, in May 2010, the Montgomery County Council imposed a levy on major emitters of CO2 in Montgomery County, which we estimate will impose on Mirant Mid-Atlantic an additional $10 million to $15 million per year of levies owed to Montgomery County. See Note K to our unaudited condensed consolidated financial statements contained elsewhere in this report for discussion of the action filed against Montgomery County in the United States District Court for the District of Maryland by Mirant Mid-Atlantic. Many of the states where we own generating facilities, including California, Maryland, Massachusetts and New York, have recently committed, or expressed an intent to commit, to mandatory reductions in statewide CO2 emissions through a regional cap-and-trade program. Maryland, Massachusetts and New York have already joined the RGGI, which required all allowances to be purchased initially through an auction process, the first of which took place in September 2008. Auctions, such as those mandated by the RGGI, may decrease the amount of available allowances and substantially increase emissions allowance prices. With respect to federal CO2 legislation, the United States House of Representatives passed a bill that would establish a cap-and-trade program for CO2 across multiple sectors, including the electric generating sector. In the House bill, the electric industry is granted a portion of allowances needed to comply with the program. The remaining allowances needed would have to be purchased through an auction process. The EPA has also begun regulating greenhouse gases from vehicles, which in turn has imposed certain permitting requirements on new large sources of CO2 and major modifications to large sources. Because our generating facilities emit CO2, regulations seeking to reduce emissions of CO2, fees or taxes tied to emissions of CO2 or other greenhouse gases and similar future laws may significantly increase our operating costs.

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

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

As a result of the coal combustion process, we produce significant quantities of ash at our coal-fired generating units that must be disposed of at sites permitted to handle ash. For most of our ash, we use our own ash management facilities, which are all dry landfills, in Maryland to dispose of the ash; however, one of these has reached design capacity and we expect that another one of these sites may reach full capacity in the next few years. As a result, we have developed a plan related to the disposition of ash, including developing new ash management facilities and preparing our ash for beneficial uses, but the costs associated with the plan could be material. The costs associated with purchasing new land and permitting the land to allow for ash disposal could be material, and the amount of time needed to obtain permits for the land could extend beyond the expected timeline. Additionally, costs associated with third-party ash handling and disposal are material and could have an adverse effect on our financial performance and condition.

We also produce gypsum as a byproduct of the SO2 scrubbing process at our coal-fired generating facilities, which is sold to third parties for use in drywall production. Should our ability to sell such gypsum to third parties be restricted as a result of the lack of demand or otherwise, our gypsum disposal costs could rise materially.

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

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

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

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

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

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

Risks Related to Level of Indebtedness

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

As of June 30, 2010, our consolidated indebtedness was $2.562 billion. In addition, the present value of lease payments under the Mirant Mid-Atlantic leveraged leases was approximately $921 million (assuming a 10% discount rate) and the termination value of the Mirant Mid-Atlantic leveraged leases was $1.3 billion. Our indebtedness and obligations under the leveraged leases could have important consequences, including the following: (1) they may limit our ability to obtain additional debt or equity financing for working capital, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; (2) a substantial portion of our cash flows from operations must be dedicated to the payment of rent and principal and interest on our indebtedness and will not be available for other purposes, including our operations, capital expenditures and future business opportunities; (3) the debt service requirements of our indebtedness could make it difficult for us to satisfy or refinance our financial obligations; (4) certain of our borrowings, including borrowings under our senior secured credit facilities, are at variable rates of interest, exposing us to the risk of increased interest rates; (5) they may limit our ability to adjust to changing market conditions and place us at a competitive disadvantage compared with our competitors that have less debt and are not burdened by such obligations and restrictions; and (6) we may be more vulnerable in a downturn in general economic conditions or in our business and we may be unable to carry out capital expenditures that are important to our long-term growth or necessary to comply with environmental regulations.

As discussed in Item 2. Management s Discussion and Analysis of Results of Operations and Financial Condition Liquidity and Capital Resources, at the closing of the merger, and as a condition thereto, the Mirant North America senior secured revolving credit facility and term loans are expected to be repaid and the Mirant North America senior notes are expected to be called for redemption.

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

We and certain of our subsidiaries, including Mirant Americas Generation and Mirant North America, are holding companies and, as a result, we are dependent upon dividends, distributions and other payments from our operating subsidiaries to generate the funds necessary to meet our obligations. The ability of certain of our subsidiaries to pay dividends and distributions is restricted under the terms of their debt or other agreements. In particular, a significant portion of cash from our operations is generated by the power generating facilities of Mirant Mid-Atlantic.

Under the Mirant Mid-Atlantic leveraged leases, Mirant Mid-Atlantic is subject to a covenant that restricts its right to make distributions to its immediate parent, Mirant North America. In turn, Mirant North America is subject to covenants that restrict its ability to make distributions to its parent, Mirant Americas Generation. The ability of Mirant North America and Mirant Mid-Atlantic to satisfy the criteria set forth in their respective debt covenants in the future could be impaired by factors which negatively affect their financial performance, including interruptions in operations or curtailments of operations to comply with environmental restrictions, significant capital and other expenditures, and adverse conditions in the power and fuel markets. Further, the Mirant North America senior notes and senior secured credit facilities include financial covenants that exclude from the calculation the financial results of any subsidiary that is unable to make distributions or dividends at the time of such calculation. Thus, the inability of Mirant Mid-Atlantic to make distributions to Mirant North America under the leveraged lease transactions would have a material adverse effect on the calculation of the financial covenants under the senior notes and senior secured credit facilities of Mirant North America, including the leverage and interest coverage maintenance covenants under its senior credit facility.

Further, we anticipate that the Mirant Marsh Landing generating facility will be financed pursuant to a project financing and, accordingly, will have restrictions in its ability to make distributions under the terms of those debt agreements.

The obligations of Mirant Corporation and its holding company subsidiaries, including the indebtedness of Mirant Americas Generation and Mirant North America, are effectively subordinated to the obligations or indebtedness of their respective subsidiaries, including the Mirant Mid-Atlantic leveraged leases.

As discussed in Item 2. Management s Discussion and Analysis of Results of Operations and Financial Condition Liquidity and Capital Resources, at the closing of the merger, and as a condition thereto, the Mirant North America senior secured revolving credit facility and term loans are expected to be repaid and the Mirant North America senior notes are expected to be called for redemption.

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

Our ability to pay principal and interest on our debt depends on our future operating performance. If our cash flows and capital resources are insufficient to allow us to make scheduled payments on our debt, we may have to reduce or delay capital expenditures, sell assets, seek additional capital, restructure or refinance. There can be no assurance that the terms of our debt will allow these alternative measures, that the financial markets will be available to us on acceptable terms or that such measures would satisfy our scheduled debt service obligations.

We seek to manage the risks associated with the volatility in the price at which we sell power produced by our generating facilities and in the prices of fuel, emissions allowances and other inputs required to produce such power by entering into hedging transactions. These asset management activities may require us to post collateral either in the form of cash or letters of credit. As of June 30, 2010, we had approximately $77 million of posted cash collateral and $228 million of letters of credit outstanding primarily to support our asset management activities, debt service and rent reserve requirements and other commercial arrangements. Although we seek to structure transactions in a way that reduces our potential liquidity needs for collateral, we may be unable to execute our hedging strategy successfully if we are unable to post the amount of collateral required to enter into and support hedging contracts.

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

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

As of June 30, 2010, we repurchased 551 shares of common stock for approximately $5,786 for the settlement of payroll taxes associated with the vesting of restricted stock units. These restricted stock units relate to grants that were made to executives and certain employees and are not related to a publicly announced share repurchase plan. See Note G contained elsewhere in this report for additional information related to stock-based compensation.

The following table sets forth information regarding repurchases of our common stock during the three-month period ended June 30, 2010:

Period	Total number of shares repurchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans	Approximate dollar value of shares that may yet be purchased under the plans
April 1, 2010 April 30, 2010		$		$
May 1, 2010 May 31, 2010	551	$ 10.50		$
June 1, 2010 June 30, 2010		$		$
Total	551			

Item 6. Exhibits

(a) Exhibits.

Exhibit No.	Exhibit Name
2.1	Agreement and Plan of Merger, dated as of April 11, 2010, by and among RRI Energy, Inc., RRI Energy Holdings, Inc. and Mirant Corporation (Incorporated herein by reference to Exhibit 2.1 to the Registrant s Current Report on Form 8-K filed April 12, 2010)
3.1	Amended and Restated Certificate of Incorporation of Registrant (Incorporated herein by reference to Exhibit 3.1 to the Registrant s Current Report on Form 8-K filed January 3, 2006)
3.2	Amended and Restated Bylaws of Registrant (Incorporated herein by reference to Exhibit 3.2 to the Registrant s Current Report on Form 8-K filed August 6, 2009)
4.1	Rights Agreement, dated as of March 26, 2009, between Mirant Corporation and Mellon Investor Services LLC (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed March 27, 2009)
4.2	First Amendment to the Rights Agreement, dated as of February 25, 2010, between Mirant Corporation and Mellon Investor Services LLC. (Incorporated herein by reference to Exhibit 4.26 to the Registrant s Annual Report on Form 10-K filed February 26, 2010)
4.3	Second Amendment to the Rights Agreement, dated as of April 28, 2010, between Mirant Corporation and Mellon Investor Services LLC. (Incorporated herein by reference to Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed April 28, 2010)
4.4	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*	Amended and Restated Mirant Services Severance Pay Plan
10.2*	Engineering, Procurement and Construction Agreement, dated as of May 6, 2010, between Mirant Marsh Landing, LLC and Kiewit Power Constructors Co.
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**	The following unaudited financial statements from the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, formatted in XBRL (Extensible Business Reporting Language): (i) the Condensed Consolidated Statements of Operations, (ii) the Condensed Consolidated Balance Sheets, (iii) the Condensed Consolidated Statements of Stockholders Equity and Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, and (v) Notes to Condensed Consolidated Financial Statements, tagged as blocks of text.

* Asterisk indicates exhibits filed herewith.

** To be filed by amendment.

The Registrant has requested confidential treatment for certain portions of this Exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

MIRANT CORPORATION

Date: August 6, 2010

By: /s/ ANGELA M. NAGY
Angela M. Nagy
Vice President and Controller
(Duly Authorized Officer and
Principal Accounting Officer)