MIRANT CORP
Form 10-K
February 27, 2009
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

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 (State or Other Jurisdiction of Incorporation or Organization)	**20-3538156** (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)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	**New York Stock Exchange**
Series A Warrants	**New York Stock Exchange**
Series B Warrants	**New York Stock Exchange**

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

None

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

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

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. x Yes ¨ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer x	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 Act). ¨ Yes x No

Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $6,974,396,638 on June 30, 2008 (based on $39.15 per share, the closing price in the daily composite list for transactions on the New York Stock Exchange that day).

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. x Yes ¨ No

As of February 20, 2009, there were 144,127,672 shares of the registrant s Common Stock, $0.01 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s proxy statement for the 2009 Annual Meeting of Stockholders are incorporated by reference in Part III of this Form 10-K to the extent described herein.

TABLE OF CONTENTS

Glossary of Certain Defined Terms

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.

CAMR Clean Air Mercury Rule.

CCX Chicago Climate Exchange.

CERCLA Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980.

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.

DWR California Department of Water Resources.

EBITDA Earnings before interest, taxes, depreciation and amortization.

EITF The Emerging Issues Task Force formed by the Financial Accounting Standards Board.

EITF 02-3 EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*

EOB California Electricity Oversight Board.

EPA United States Environmental Protection Agency.

EPS Earnings per share.

ERISA Employee Retirement Income Security Act of 1974.

FASB Financial Accounting Standards Board.

FERC Federal Energy Regulatory Commission.

FIN FASB Interpretation.

FIN 39 FIN No. 39, *Offsetting of Amounts Related to Certain Contracts.*

FIN 45 FIN No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others An Interpretation of FASB Statements Nos. 5, 57, and 107 and Rescission of FASB Interpretation No. 34.*

FIN 46R FIN No. 46(R), *Consolidation of Variable Interest Entities (Revised December 2003) an Interpretation of Accounting Research Bulletin No. 51*.

FIN 47 FIN No. 47, *Accounting for Conditional Asset Retirements an interpretation of FASB Statement No. 143*.

FIN 48 FIN No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*.

FSP FASB Staff Position.

FSP FAS 132R-1 FSP FAS No. 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets (Revised 2003)*.

FSP FAS 157-2 FSP FAS No. 157-2, *Effective Date of FASB Statement No. 157*.

FSP FAS 157-3 FSP FAS No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active.*

FSP FIN 39-1 FSP FIN No. 39-1, *Amendment of FASB Interpretation No. 39 (FIN 39).*

GAAP Generally accepted accounting principles in the United States.

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

Hudson Valley Gas Hudson Valley Gas Corporation.

IBEW International Brotherhood of Electrical Workers.

InterContinental Exchange InterContinental Exchange, Inc.

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

ISO Independent System Operator.

ISO-NE Independent System Operator-New England.

kW Kilowatt.

LIBOR London InterBank Offered Rate.

LTSA Long-term service agreement.

MC Asset Recovery MC Asset Recovery, LLC.

MDE Maryland Department of the Environment.

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

Mirant Americas Mirant Americas, Inc.

Mirant Americas Energy Marketing Mirant Americas Energy Marketing, LP.

Mirant Americas Generation Mirant Americas Generation, LLC.

Mirant Asia-Pacific Mirant Asia-Pacific Limited sold by the Company in the second quarter of 2007.

Mirant Bowline Mirant Bowline, LLC.

Mirant Canal Mirant Canal, LLC.

Mirant Chalk Point Mirant Chalk Point, LLC.

Mirant Delta Mirant Delta, LLC.

Mirant Energy Trading Mirant Energy Trading, LLC.

Mirant Kendall Mirant Kendall, LLC.

Mirant Lovett Mirant Lovett, 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 Pagbilao Mirant Pagbilao Corporation sold by the Company in the second quarter of 2007.

Mirant Potomac River Mirant Potomac River, LLC.

Mirant Potrero Mirant Potrero, LLC.

Mirant Power Purchase Mirant Power Purchase, LLC.

Mirant Services Mirant Services, LLC.

Mirant Sual Mirant Sual Corporation sold by the Company in the second quarter of 2007.

Mirant Trinidad Investments Mirant Trinidad Investments, LLC sold by the Company in the third quarter of 2007.

MW Megawatt.

MWh Megawatt hour.

NAAQS National ambient air quality standard.

NEPOOL New England Power Pool.

NERC North American Electric Reliability Council.

Net Capacity Factor The average production as a percentage of the potential net dependable capacity used over a year.

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

NOL Net operating loss.

NOV Notice of violation.

NOx Nitrogen oxides.

NPCC Northeastern Power Coordinating Council.

NSR New source review.

NYISO Independent System Operator of New York.

NYMEX New York Mercantile Exchange.

NYSDEC New York State Department of Environmental Conservation.

NYSE New York Stock Exchange.

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

Orange and Rockland Orange and Rockland Utilities, Inc.

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.

Petition Date July 14, 2003, the date Mirant and certain of its subsidiaries filed voluntary petitions for relief with the Bankruptcy Court.

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.

PUHCA Public Utility Holding Company Act of 2005.

Reserve Margin Excess capacity over peak demand.

RFC ReliabilityFirst Corporation.

RGGI Regional Greenhouse Gas Initiative.

RMR Reliability-must-run.

RTO Regional Transmission Organization.

SAB SEC Staff Accounting Bulletin.

SAB 107 SAB No. 107, *Share-Based Payment.*

SAB 110 SAB No. 110, *Share-Based Payment an amendment of SAB No. 107.*

SEC U.S. Securities and Exchange Commission.

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.

SFAS Statement of Financial Accounting Standards.

SFAS 5 SFAS No. 5, *Accounting for Contingencies*.

SFAS 107 SFAS No. 107, *Disclosure about Fair Value of Financial Instruments.*

SFAS 109 SFAS No. 109, *Accounting for Income Taxes*.

SFAS 123R SFAS No. 123(R), *Share-Based Payment (Revised 2004).*

SFAS 133 SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities (As Amended)*.

SFAS 141R SFAS No. 141(R), *Business Combinations (Revised 2007).*

SFAS 142 SFAS No. 142, *Goodwill and Other Intangible Assets.*

SFAS 143 SFAS No. 143, *Accounting for Asset Retirement Obligations*.

SFAS 144 SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

SFAS 157 SFAS No. 157, *Fair Value Measurements.*

SFAS 158 SFAS No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans: An Amendment of FASB Statements Nos. 87, 88, 106 and 132(R)*.

SFAS 159 SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*.

Table of Contents

SFAS 161 SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities An Amendment of FASB Statement No. 133*.

Shady Hills Shady Hills Power Company, L.L.C. sold by the Company in the second quarter of 2007.

SO2 Sulfur dioxide.

SOP 90-7 Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*.

UWUA Utility Workers Union of America.

VaR Value at risk.

VIE Variable interest entity.

Virginia DEQ Virginia Department of Environmental Quality.

WECC Western Electric Coordinating Council.

West Georgia West Georgia Generating Company, L.L.C. sold by the Company in the second quarter of 2007.

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

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In addition to historical information, the information presented in this Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the 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;
- changes in market conditions, including developments in the supply, demand, volume and pricing of electricity and other commodities in the energy markets 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;
- our inability to access effectively the OTC and exchange-based commodity markets or changes in commodity market conditions and liquidity, 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 counterparties to pay amounts owed to us or to perform obligations or services due to us beyond collateral posted;
- hazards customary to the power generation industry and the possibility that we may not have adequate insurance to cover losses as a result of such hazards;
- 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 in the markets in which we operate;

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 and to obtain adequate supply and delivery of fuel for our facilities, at our required specifications and on terms and prices acceptable to us;

Table of Contents

- the inability of our operating subsidiaries to generate sufficient cash flow to support our operations;
- our ability to borrow additional funds and access capital markets;
- strikes, union activity or labor unrest;
- weather and other natural phenomena, including hurricanes and earthquakes;
- the cost and availability of emissions allowances;
- curtailment of operations because of transmission constraints;
- environmental 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;
- our inability to complete construction of emissions reduction equipment by January 2010 to meet the requirements of the Maryland Healthy Air Act, which may result in reduced unit operations and reduced cash flows and revenues from operations;
- our ability to execute our business plan in California, including entering into long-term power sales agreements for new generating facilities at our existing sites and entering into new tolling arrangements for our existing generating facilities;
- the ability of lenders under Mirant North America s revolving credit facility to perform their obligations;
- war, terrorist activities or the occurrence of a catastrophic loss;
- 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; and
- the disposition of the pending litigation described in this Form 10-K.

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 consolidated financial statements, other factors that could affect our future performance (business, financial condition or results of operations and cash flows) are set forth in Item 1A. Risk Factors.

Certain Terms

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

Table of Contents

PART I

Item 1. *Business*

Overview

We are a competitive energy company that produces and sells electricity in the United States. We own or lease 10,112 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. Our customers are principally ISOs, RTOs and investor-owned utilities. Our generating portfolio is diversified across fuel types, power markets and dispatch types and serves customers located near many major metropolitan load centers. Our total net generating capacity is approximately 30% baseload, 58% intermediate and 12% peaking.

Mirant Corporation was incorporated in Delaware on September 23, 2005. Pursuant to the Plan for Mirant and certain of its subsidiaries, on January 3, 2006, New Mirant emerged from bankruptcy and acquired substantially all of the assets of Old Mirant, a corporation that was formed in Delaware on April 3, 1993, and that had been named Mirant Corporation prior to January 3, 2006. The Plan provides that New Mirant has no successor liability for any unassumed obligations of Old Mirant. Old Mirant was then renamed and transferred to a trust, which is not affiliated with New Mirant.

We are focused on the operational performance of our generating facilities, generation of cash from operations and prudent growth of our business.

In 2008, we invested $672 million in our generating facilities. Much of this amount was invested in emissions control equipment to comply with the Maryland Healthy Air Act. We are installing flue gas desulphurization (FGD) emissions controls at our Chalk Point, Dickerson and Morgantown coal-fired units. In addition, we have installed selective catalytic reduction systems at the Morgantown coal-fired units and one of the Chalk Point coal-fired units and a selective auto catalytic reduction system at the other Chalk Point coal-fired unit. We are installing selective non-catalytic reduction systems at the three Dickerson coal-fired units. Including amounts already spent to date, we will invest $1.674 billion on emissions reduction controls. These controls will be capable of reducing emissions of SO_2, NO_x and mercury by approximately 98%, 90% and 80%, respectively, for three of our largest coal-fired units.

Our investments in our generating facilities also reflect our targeted maintenance program to ensure consistent long-term availability of our generating facilities. Our equivalent forced outage rate was 8% in 2008 compared to 10% in 2007 for our Mid-Atlantic baseload coal-fired units excluding our Potomac River facility.

In 2008, we observed significant volatility in commodity prices. Our hedging program reduced our exposure to this volatility and contributed $207 million to our realized gross margin for 2008. In 2008, we generated $677 million of net cash provided by operating activities of our continuing operations.

As we generate excess cash from our operations, we will invest it in our business, but only when it is prudent to do so. Our existing generating facility sites have room to add an additional 7,500 MW to 10,000 MW of generating capacity and we continue to consider these opportunities.

We will return excess cash to our stockholders when we cannot prudently invest it in our business. In 2007, we sold our Philippine and Caribbean businesses, six U.S. natural gas-fired facilities and Mirant NY-Gen. After transaction costs and repayment of debt, the net proceeds to us from dispositions completed for the year ended December 31, 2007, were approximately $5.071 billion. Between November 2007 and December 2008, we returned approximately $4.056 billion of cash to our stockholders through purchases of 122 million shares of our common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion.

5

Table of Contents

The annual, quarterly and current reports, and any amendments to those reports, that we file with or furnish to the SEC are available free of charge on our website at www.mirant.com as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. General information about us, including our Corporate Governance Guidelines, the charters for our Audit, Compensation, and Nominating and Governance Committees, and our Code of Ethics and Business Conduct, can also be found at www.mirant.com. We will provide print copies of these documents to any stockholder upon written request to Corporate Secretary, Mirant Corporation, 1155 Perimeter Center West, Suite 100, Atlanta, Georgia 30338-5416. Information contained on our website is not incorporated into this Form 10-K.

Business Segments

We have four operating segments: Mid-Atlantic, Northeast, California and Other Operations. The Mid-Atlantic segment consists of four generating facilities located in Maryland and Virginia near Washington, D.C. The Northeast segment consists of three generating facilities located in Massachusetts and one generating facility located in New York near New York City. The California segment consists of three generating facilities located in or near San Francisco. Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances. For the years ended December 31, 2007 and 2006, Other Operations also included gains and losses related to a long-term PPA with Pepco (the Back-to-Back Agreement), which was terminated pursuant to a settlement agreement that became effective in the third quarter of 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Back-to-Back Agreement.

The table below presents our capacity by region and our Net Capacity Factor for the year ended December 31, 2008:

Region	Total Capacity (MW)	Net Capacity Factor
Mid-Atlantic	5,230	33%
Northeast	2,535	13%
California	2,347	4%

The table below summarizes selected financial information of our continuing operations by business segment for the year ended December 31, 2008 (dollars in millions):

Business Segment	Revenues	%	Gross Margin	%	Operating Income/ (Loss)	%
Mid-Atlantic	$ 2,279	72%	$ 1,714	81%	$ 1,218	91%
Northeast	617	19%	179	8%	23	2%
California	186	6%	127	6%	35	2%
Other Operations	102	3%	103	5%	67	5%
Eliminations	4	%	6	%	(2)	%
Total	$ 3,188	100%	$ 2,129	100%	$ 1,341	100%

Eliminations are primarily related to intercompany sales of emissions allowances. For selected financial information about our business segments, see Note 14 to our consolidated financial statements contained elsewhere in this report. See Item 2. Properties for a complete list of our generating facilities.

Asset Management

Our commercial operations consist primarily of procuring fuel, dispatching electricity, hedging the production and sale of electricity by our generating facilities, managing fuel and providing logistical support for

6

Table of Contents

the operation of our facilities (for example, by procuring transportation for coal). We typically sell the electricity we produce into the wholesale market at prices in effect at the time we produce it (the spot price). Spot prices for electricity are volatile, as are prices for fuel and emissions allowances, and in order to reduce the risk of that volatility and achieve more predictable financial results, it is our strategy to enter into hedges forward sales of electricity and forward purchases of fuel and emissions allowances to permit us to produce and sell the electricity for various time periods. In addition, given the high correlation between natural gas prices and electricity prices in the markets in which we operate, we enter into forward sales of natural gas to hedge our exposure to changes in the price of electricity. We procure our hedges in OTC transactions or on exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with buyers and sellers, using futures, forwards, swaps and options. We also sell capacity and ancillary services where there are markets for such products and when it is economic to do so.

We use dispatch models to assist us in making daily decisions regarding the quantity and price of the power our facilities will generate and sell into the markets. We bid the energy from our generating facilities into the day-ahead energy market and sell ancillary services through the ISO and RTO markets. We sell capacity either bilaterally or through auction processes in each ISO and RTO in which we participate. We work with the ISOs and RTOs in real time to ensure that our generating facilities are dispatched economically to meet the reliability needs of the market.

At February 10, 2009, our aggregate hedge levels based on expected generation for each period were as follows:

	Aggregate Hedge Levels Based on Expected Generation				
	2009	2010	2011	2012	2013
Power	96%	62%	22%	24%	24%
Fuel	90%	64%	53%	29%	6%

Power

We hedge economically a substantial portion of our Mid-Atlantic coal-fired baseload generation and certain of our 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. A significant portion 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. We also enter into forward sales of natural gas to hedge our exposure to changes in the price of electricity.

While OTC transactions make up a substantial portion of our economic hedge portfolio, at times we sell non-standard, structured products to customers. Additionally, our California facilities operate under contracted capacity and RMR contracts.

Fuel

We enter into contracts of varying terms to secure appropriate quantities of fuel that meet the varying specifications of our generating facilities. For our coal-fired generating facilities, we purchase coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2013. For our oil-fired units, we typically purchase fuel from a limited number of suppliers under contracts with terms of varying lengths.

Our coal supply comes primarily from the Central Appalachian and Northern Appalachian coal regions. Most of our coal is delivered by rail, except for a portion of our coal deliveries at our Morgantown station, which is received by barge at our unloading facility that became operational in the third quarter of 2008. The barge

Table of Contents

unloader enables us to receive coal from international locations as well. We monitor coal supply and delivery logistics carefully and, despite occasional interruptions of scheduled deliveries, to date we have managed to avoid any significant detrimental effects on our operations. We typically maintain a target level of coal inventory at our coal-fired facilities for this purpose. Interruptions of scheduled deliveries can result from a variety of disruptions, including coal supplier operational issues, rail system disruptions or severe weather.

Emissions

Our commercial operations manage the acquisition and use of emissions allowances for our generating facilities. Primarily as a result of the pollution control equipment we are installing to comply with the requirements of the Maryland Healthy Air Act, we have significant excess SO2 and NOx emissions allowances for future periods. We plan to continue to maintain some SO2 and NOx emissions allowances in excess of what we need to support our expected generation in case our actual generation exceeds our current forecasts for future periods and for possible future additions of generating capacity. During the fourth quarter of 2007, we began a program to sell excess SO2 and NOx emissions allowances under certain market conditions. At December 31, 2008, the estimated fair value of our excess SO2 and NOx emissions allowances exceeded the carrying value recorded on our consolidated balance sheet by approximately $63 million.

In September 2008, we joined the CCX, which is a voluntary greenhouse gas registry, reduction and trading system. As part of the agreement for membership in CCX, we have committed to meet annual emissions reduction targets and, by 2010 to reduce our greenhouse gas emissions by six percent below the average of our 1998 to 2001 levels. We expect to satisfy our reduction targets primarily through previously implemented generating unit retirements and capacity factor reductions.

Mid-Atlantic Region

We own or lease four generating facilities in the Mid-Atlantic region with total net generating capacity of 5,230 MW. Our Mid-Atlantic region had a combined 2008 Net Capacity Factor of 33%.

The following table presents the details of our Mid-Atlantic generating facilities:

Facility	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location	NERC Region
Chalk Point	2,413	Natural Gas/Coal/Oil	Intermediate/ Baseload/Peaking	Maryland	RFC
Dickerson	849	Natural Gas/Coal/Oil	Baseload/Peaking	Maryland	RFC
Morgantown	1,486	Coal/Oil	Baseload/Peaking	Maryland	RFC
Potomac River	482	Coal	Baseload/ Intermediate	Virginia	RFC
Total Mid-Atlantic	5,230				

The Chalk Point facility is our largest generating facility. It consists of two coal-fired baseload units, two dual-fueled (oil and gas) intermediate units and two oil-fired and five dual-fueled (oil and gas) peaking units. Our next largest facility is the Morgantown facility. It consists of two coal-fired baseload units and six oil-fired peaking units. The Dickerson facility has three coal-fired baseload units, and one oil-fired and two dual-fueled (oil and gas) peaking units. The Potomac River facility has three coal-fired baseload units and two coal-fired intermediate units.

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

Table of Contents

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 is included in funds on deposit and other noncurrent assets in the accompanying consolidated balance sheets and in our estimated capital expenditures presented in Item 7. Management s Discussion and Analysis of Results of Operations and Financial Condition Overview . See Note 17 to our consolidated financial statements contained elsewhere in this report for a more detailed discussion on the Potomac River Settlement.

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 we merged the stacks for units 3, 4 and 5 into one stack at the Potomac River generating facility and, in January 2009, we merged the stacks for units 1 and 2 into one stack. With the completion of the stack combinations, the permit issued in July 2008 will not constrain operations of the Potomac River generating facility below historical operations and will allow operation of all five units at one time. Certain provisions of Virginia s air emissions regulations adopted to implement the CAIR, however, could constrain the facility s operations, as described below in *Environmental Regulation-Virginia CAIR Implementation* .

Northeast Region

We own generating facilities in the Northeast region with total net generating capacity of 2,535 MW. Our Northeast region had a combined 2008 Net Capacity Factor of 13%. The Northeast region is comprised of our facilities located in Massachusetts and New York. Generation is sold from our Northeast facilities through a combination of bilateral contracts, spot market transactions and structured transactions.

The following table presents the details of our facilities in the Northeast Region:

Facility	**Total Net Generating Capacity (MW)**	**Primary Fuel Type**	**Dispatch Type**	**Location**	**NERC Region**
Bowline	1,139	Natural Gas/Oil	Intermediate/ Peaking	New York	NPCC
Canal	1,126	Natural Gas/Oil	Intermediate	Massachusetts	NPCC
Kendall	256	Natural Gas/Oil	Baseload/Peaking	Massachusetts	NPCC
Martha s Vineyard	14	Diesel	Peaking	Massachusetts	NPCC
Total Northeast Region	2,535				

The Bowline facility is a dual-fueled (natural gas and oil) facility comprised of two intermediate/peaking units. The capacity, energy and ancillary services from our Bowline generating facility are sold into the bilateral markets and into the markets administered by the NYISO. For a discussion of the NYISO, see *Regulatory Environment* below.

The Canal facility consists of one oil-fired intermediate unit and one dual-fueled (oil and gas) intermediate unit. The Kendall facility consists of one combined cycle dual-fueled (oil and gas) baseload unit, two 1,300 pound steam boilers and one simple cycle jet engine peaking unit. The Martha s Vineyard facility consists of five diesel peaking units. The capacity, energy and ancillary services from our Massachusetts generating units are sold into the NEPOOL bilateral markets and into the markets administered by the ISO-NE. For a discussion of the NEPOOL and the ISO-NE, see *Regulatory Environment* below. The Kendall facility also has long-term agreements under which it sells steam resulting from electricity production or is reimbursed for production costs when called upon to provide steam under the agreements.

Table of Contents

The Canal facility is located in the lower Southeastern Massachusetts (SEMA) area in ISO-NE. ISO-NE has previously determined that, at times, it is necessary for the Canal facility to operate to meet local reliability criteria for SEMA when it was not economic for the Canal facility to operate based upon prevailing market prices. When the Canal facility operates to meet local reliability criteria, we are compensated at the price we bid into the ISO-NE rather than at the lower market price.

ISO-NE and NSTAR recently developed a plan to upgrade the SEMA transmission system that will reduce the local reliability need for the Canal facility. These transmission upgrades are scheduled for completion in September 2009. Once these upgrades are completed, we expect that the need for the Canal facility to operate for reliability will be reduced. As such, the gross margin from our Canal facility may decrease significantly compared to that generating facility s gross margin for recent years.

On June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into a consent decree (the 2003 Consent Decree) governing the future of the Lovett facility s two coal-fired units (units 4 and 5). Pursuant to the 2003 Consent Decree as amended on May 10, 2007, we discontinued operation of unit 4 as of May 7, 2007, and unit 5 on April 19, 2008. In addition, we discontinued operation as of May 7, 2007, of unit 3, a dual-fueled unit (natural gas and oil), the only other operating unit at the facility because it was uneconomic to run the unit. We have substantially completed the demolition of the Lovett facility.

California

We own three generating facilities in California with total net generating capacity of 2,347 MW. Our California facilities had a combined 2008 Net Capacity Factor of 4%. The following table presents the details of our California facilities:

Facility	Total Net Generating Capacity (MW)	Primary Fuel Type	Dispatch Type	Location	NERC Region
Contra Costa	674	Natural Gas	Intermediate	California	WECC
Pittsburg	1,311	Natural Gas	Intermediate	California	WECC
Potrero	362	Natural Gas/Diesel	Intermediate/ Peaking	California	WECC
Total California	2,347				

The Contra Costa and Pittsburg facilities are located in Contra Costa County and the Potrero facility is located in the City of San Francisco. The Contra Costa facility consists of two gas-fired intermediate units and the Pittsburg facility consists of three gas-fired intermediate units. The Potrero facility consists of one gas-fired intermediate unit and three diesel peaking units. Through the end of 2006, the majority of our California units were subject to RMR arrangements with the CAISO. These agreements are described further under *Regulatory Environment* below. Pittsburg unit 7 and Contra Costa unit 6 were not subject to an RMR arrangement, and thus functioned solely as merchant facilities in the CAISO. In 2006, we either sold the output of Pittsburg unit 7 and Contra Costa unit 6 into the market through bilateral transactions with utilities and other merchant generators, or dispatched the units in the CAISO clearing markets.

On July 28, 2006, we signed two tolling agreements with PG&E to provide electricity from all our natural gas-fired units in service at Contra Costa and Pittsburg, including Contra Costa unit 6 and Pittsburg unit 7. The agreements are for 100% of the capacity from these units. The contracts have varying tenors for each unit covering from one to five years, and include capacity of 1,985 MW for 2008 and 2009, 1,303 MW for 2010 and 674 MW for 2011. We receive monthly capacity payments with bonuses and/or penalties based on guaranteed heat rate and availability tolerances. As a result of these contracts, the Contra Costa and Pittsburg units are no longer subject to the RMR agreements.

Table of Contents

All of our Potrero units continue to be subject to RMR arrangements through 2009 and annually thereafter based upon the CAISO s local reliability requirements.

Our generating facilities in California depend almost entirely on payments they receive to operate in support of system reliability. The energy, capacity and ancillary services markets, as currently constituted, will not support the capital expenditures necessary to repower or reconstruct our facilities to make them commercially viable in a merchant market. In order to obtain the necessary capital support for repowering or reconstructing our facilities, we will need to obtain a contract with a creditworthy buyer. Absent that, our generating facilities in California will be commercially viable only as long as they are necessary for reliability.

Other Operations

In addition to selling the electricity we produce and buying the fuel and emissions allowances we need to produce electricity (asset management), we buy and sell some electricity, fuel and emissions allowances as part of our proprietary trading and fuel oil management activities.

We engage in proprietary trading to gain information about the markets to support our asset management and to take advantage of selected opportunities that we identify from time to time. We enter into fuel oil management activities to hedge economically the fair value of our physical fuel oil inventories and to optimize the approximately three and one half million barrels of storage capacity that we own or lease.

Proprietary trading and fuel oil management activities together typically comprise less than 10% of our realized gross margin. All of our commercial activities are governed by a comprehensive Risk Management Policy, which includes limits on the size of positions and VaR for our proprietary trading and fuel oil management activities. For 2008, our average daily VaR for these activities was approximately $2 million.

Competitive Environment

The power generating industry is capital intensive and highly competitive. Our competitors include regulated utilities, merchant energy companies, financial institutions and other companies, including companies owned by hedge funds and private equity funds. For a discussion of competitive factors and the effects of seasonality on our business see Item 1A. Risk Factors . Coal-fired generation, natural gas-fired generation and nuclear generation currently account for approximately 48%, 22% and 19%, respectively, of the electricity produced in the United States. Hydroelectric and other energy sources account for the remaining 11% of electricity produced.

The recent economic downturn and programs to reduce the demand for electricity have resulted in a decrease in the rate at which the long-term demand for electricity is forecasted to grow. Given the substantial time necessary to permit and construct new power plants, the process to add generating capacity must begin years in advance of anticipated growth in demand. A number of ISOs and RTOs, including those in markets in which we operate, have implemented capacity markets as a way to encourage construction of additional generation, but it is not clear whether and when independent power producers will be sufficiently incented to build this required new generation. The costs to construct new generation facilities have been rising and there is substantial environmental opposition to building either coal-fired or nuclear plants.

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

The average market price for the types of coal that we use was approximately 107% higher in the year ended December 31, 2008, than in 2007. Global demand for coal to generate electricity has been a significant factor influencing domestic prices for the types of coal that we use. At the same time, the prices for power and natural

Table of Contents

gas were extremely volatile, increasing during the first half of 2008 and decreasing during the second half of 2008. Fluctuations in natural gas prices have a significant effect on the price of power, especially in the PJM market where the marginal price for power is often set by gas-fired units. In 2008 as compared to 2007, the energy gross margin earned from our baseload coal units was negatively affected by contracting dark spreads, the difference between the price received for electricity generated compared to the market price of the coal required to produce the electricity. In the fourth quarter of 2008 and in early 2009, the average market price for the types of coal that we use declined from the highs observed earlier in 2008. However, the average market price for power also declined during the same period.

Climate change concerns have led to significant legislative and regulatory efforts at the state and federal level to limit greenhouse gas emissions, including CO2. The costs of compliance with such efforts could affect our ability to compete in the markets in which we operate, especially with our coal-fired generating facilities.

Regulatory Environment

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

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

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

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

Table of Contents

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

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

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

Load-serving entities within PJM are required to have adequate sources of generating capacity. Our facilities located in the Mid-Atlantic region that sell electricity into the PJM market participate in the reliability pricing model (the RPM) forward capacity market. The PJM RPM capacity auctions are designed to provide forward prices for capacity that are intended to ensure that adequate resources are in place to meet the region s demand requirements. PJM has conducted five PJM RPM capacity auctions and we began receiving payments in June 2007 as a result of the first auction. The FERC s orders approving and implementing the PJM RPM capacity auctions have been appealed to the United States Court of Appeals for the District of Columbia Circuit (the DC Circuit). We cannot predict what, if any, effect the appeal process will have on the RPM forward capacity market and the capacity payments that we have received or expect to receive from that market.

The results of the PJM RPM capacity auctions for the delivery area where our facilities are located were as follows:

Auction Date	Capacity Period	Resource Clearing Price per MW-day
April 2007	June 1, 2007 to May 31, 2008	$ 188.54
July 2007	June 1, 2008 to May 31, 2009	$ 210.11
October 2007	June 1, 2009 to May 31, 2010	$ 237.33
January 2008	June 1, 2010 to May 31, 2011	$ 174.29
May 2008	June 1, 2011 to May 31, 2012	$ 110.00

Since 2008, annual auctions have been conducted to procure capacity three years prior to each delivery period. The first annual auction took place in May 2008, for the provision of capacity from June 1, 2011 to May 31, 2012.

On December 12, 2008, PJM filed with the FERC to revise elements of the RPM forward capacity market. PJM intends to implement these changes in time for the May 2009 annual auction for the provision of capacity from June 1, 2012 to May 31, 2013. We filed an opposition to the proposed changes with the FERC. On February 9, 2009, PJM and a coalition of PJM customers (the PJM Load Group) as well as several state

Table of Contents

commissions filed a settlement agreement with the FERC that would materially modify several provisions of the December 12, 2008, filing to the detriment of suppliers in the RPM capacity auction. Under the FERC s rules and regulations, any party to a contested proceeding may unilaterally file a settlement in that proceeding with the FERC. We filed comments opposing the settlement. At this time, we do not know if the FERC will accept, reject or modify PJM s proposed changes to the RPM forward capacity market submitted in both the December 12, 2008, filing and February 9, 2009, settlement filing. Therefore, we cannot predict what effect, if any, these changes will have on the May 2009 PJM RPM auction.

Northeast Region. Our Bowline facility participates in a market controlled by the NYISO. The NYISO provides statewide transmission service under a single tariff and interfaces with neighboring market control areas. To account for transmission congestion and losses, the NYISO calculates energy prices using a locational marginal pricing model. The NYISO also administers a spot market for energy, as well as markets for installed capacity and services that are ancillary to transmission service, such as operating reserves and regulation service (which balances resources with load). The NYISO s locational capacity market rules use a demand curve mechanism to determine for every month the required amount of installed capacity as well as installed capacity prices to be paid for three locational zones: New York City, Long Island and Rest of State. Our facility operates in the Rest of State locational zone.

Our Canal, Kendall and Martha s Vineyard facilities participate in a market administered by ISO-NE. Mirant Energy Trading is a member of NEPOOL, which is a voluntary association of electric utilities and other market participants in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and which functions as an advisory organization to ISO-NE. The FERC approved ISO-NE as the RTO for the New England region making ISO-NE responsible for market rule filings at the FERC, in addition to its responsibilities for the operation of transmission systems and for the administration and settlement of the wholesale electric energy, capacity and ancillary services markets. ISO-NE utilizes a locational marginal pricing model similar to the model used in PJM and NYISO.

On March 6, 2006, a settlement proposal was filed with the FERC among ISO-NE and multiple market participants for a forward capacity market (the FCM) under which annual capacity auctions would be conducted for supply three years in advance of provision. The settlement provided for a four-year transition period during which capacity suppliers receive a set price for their capacity commencing on December 1, 2006, with price escalators through May 31, 2010. Beginning December 1, 2006, our generating facilities began receiving capacity revenues under the FCM transition period. During the FCM transition period we received or will receive capacity revenues between $3.05 per kW- month and $4.10 per kW-month. The first auction took place in February 2008 for the period June 1, 2010 to May 31, 2011. The clearing price was $4.50 per kW-month, which was the price floor established as part of the FCM settlement. Our generating facilities will receive $4.25 per kW-month based on our pro-rata amount of the generating capacity that was sold in the auction. The next auction was held in December 2008 for the period June 1, 2011 to May 31, 2012, and the clearing price was $3.60 per kW-month. Our generating facilities will receive $3.12 per kW-month based on our pro-rata amount of the generating capacity that was sold in the auction. In March 2008, the FERC s orders approving and implementing the FCM were affirmed by the DC Circuit; however, the DC Circuit reversed a portion of the FERC s orders regarding the rights of a non-settling party to challenge the FCM charges through future proceedings initiated at the FERC. On January 15, 2009, the FERC issued an order on remand, directing the settling parties to revise the applicable standard of review to be consistent with the DC Circuit s decision. We do not expect that the DC Circuit s reversal of this element of the FCM or the FERC s actions on remand will have an effect on the FCM and the capacity payments we receive under the FCM.

California. Our California facilities are located inside the CAISO s control area. The CAISO schedules transmission transactions, arranges for necessary ancillary services and administers a real-time balancing energy market. Most sales in California are pursuant to bilateral contracts, but a significant percentage of electrical energy is sold in the real-time market. The CAISO does not operate a forward market like those described for PJM and other eastern markets, nor does it currently operate a capacity market.

Table of Contents

The CAISO has proposed changes to its market design to mirror more closely the eastern markets, but not including a capacity market. Although the CAISO has delayed the market redesign several times, it now expects to fully implement it in 2009. The CPUC has begun a proceeding to develop, together with the CAISO, a wholesale capacity market. FERC approval would be required for any such capacity market to become effective. We cannot at this time predict the outcome of the CPUC proceeding or the timing or structure of a wholesale capacity market in California.

Mirant Potrero is party to a PPA with PG&E that from 2006 through 2012 allows PG&E to dispatch and purchase the output of our Potrero units that have been designated RMR units which for 2009 includes all of the Potrero units. Under the PPA, through 2008, PG&E paid us charges equivalent to the rates we charged during 2004 when the units were designated as RMR units reduced by $1.4 million for each year since 2004. For 2009 through 2012, the charges for the units that are then subject to the PPA will be determined annually by the FERC pursuant to the cost-based formula rates set forth in the RMR agreement. On December 4, 2008, the FERC issued an order approving the charges for the Potrero units for 2009 and 2010. The approved PPA charges for 2009 and 2010 are expected to result in approximately the same level of gross margin for Mirant Potrero as it recognized for 2008.

Environmental Regulation

Our business is subject to extensive environmental regulation by federal, state and local authorities. We must comply with applicable laws and regulations, and obtain and comply with the terms of government issued permits. Our costs of complying with environmental laws, regulations and permits are substantial, including significant environmental capital expenditures. See Item 7. Management s Discussion and Analysis of Results of Operations and Financial Condition Capital Expenditures and Capital Resources for additional information.

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures.

Air Emissions Regulations

Our most significant environmental requirements generally fall under the Clean Air Act, regional initiatives and similar state laws. Under the Clean Air Act, we are required to comply with a broad range of mandates concerning air emissions, operating practices and pollution control equipment. Most of our facilities are located in or near metropolitan areas, including New York City, Boston, San Francisco and Washington D.C., which are classified by the EPA as not achieving certain NAAQS (non-attainment areas). As a result of the classification of each of these areas as a non-attainment area, our operations are subject to more stringent air pollution requirements than those applicable to plants located elsewhere. Various states where we have facilities also have other air quality laws and regulations with increasingly stringent limitations and requirements that will affect us in future years. In the future, we expect increased regulation of our air emissions. Significant air regulatory programs to which we are subject are described below.

Clean Air Interstate Rule (CAIR). In 2005, the EPA promulgated the CAIR, which established in the eastern United States SO_2 and NO_x cap-and-allowance trading programs applicable directly to states and indirectly to generating facilities. These cap-and-trade programs were to be implemented in two phases, with the first phase going into effect in 2009 for NO_x and 2010 for SO_2 and more stringent caps going into effect in 2015. Various parties appealed 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.

Maryland Healthy Air Act. The Maryland Healthy Air Act was enacted in April 2006 and requires reductions in SO_2, NO_x and mercury emissions from large coal-fired power facilities. The state law also requires

Maryland to join the RGGI, which is discussed below. The Maryland Healthy Air Act prohibits power facilities from purchasing emissions allowances instead of installing emissions control equipment. We are installing FGD emissions controls at our Chalk Point, Dickerson and Morgantown coal-fired units. In addition, we have installed selective catalytic reduction systems at the Morgantown coal-fired units and one of the Chalk Point coal-fired units and a selective auto catalytic reduction system at the other Chalk Point coal-fired unit. We are installing selective non-catalytic reduction systems at the three Dickerson coal-fired units. These controls will be capable of reducing emissions of SO2, NOx and mercury by approximately 98%, 90% and 80%, respectively, for three of our largest coal-fired units.

The Maryland Healthy Air Act imposes mass limits for (i) emissions of NOx in 2009 with further reductions in 2012 (including sublimits during the Ozone Season) and (ii) emissions of SO2 in 2010 with further reductions in 2013. The Maryland Healthy Air Act also imposes restrictions on emissions of mercury beginning in 2010 with further reductions in 2013. The control equipment we have installed or are installing to meet Maryland state standards will allow our Maryland facilities to comply with (a) all of the requirements of the Maryland Healthy Air Act and (b) the first phase of the CAIR without having to purchase emissions allowances.

Including amounts already spent to date, we expect to incur total capital expenditures of $1.674 billion to comply with the requirements for SO2, NOx and mercury emissions under the Maryland Healthy Air Act. On July 30, 2007, our subsidiaries Mirant Mid-Atlantic and Mirant Chalk Point entered into an agreement with Stone & Webster, Inc. for engineering, procurement and construction services relating to the installation of the FGD systems described above. The expected cost under the agreement is approximately $1.13 billion and is a part of the $1.674 billion of capital expenditures that we expect to incur to comply with the Maryland Healthy Air Act. We will have planned outages in 2009 to complete the installation of the FGD control systems. During those outages, we also will perform routine maintenance activities. As of December 31, 2008, we have paid approximately $997 million of the $1.674 billion for capital expenditures related to the Maryland Healthy Air Act. For the year ended December 31, 2008, we paid $683 million for capital expenditures, excluding capitalized interest, of which $497 million related to the Maryland Healthy Air Act. We expect that available cash and future cash flows from operations will be sufficient to fund the remaining capital expenditures.

Clean Air Mercury Rule (CAMR). In 2005, the EPA issued the CAMR, which would have limited total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program. In February 2008, the DC Circuit vacated the CAMR and the EPA s decision to delist coal- and oil-fired electric utility steam generating units from sources regulated under section 112 of the Clean Air Act. The EPA and the Utility Air Regulatory Group sought review of the DC Circuit s decision by the United States Supreme Court. In February 2009, the EPA filed to withdraw its petition for review, stating that it intends to promulgate alternative regulations to address mercury emissions, and the United States Supreme Court subsequently denied the petition for review. As a result of the DC Circuit decision, mercury emissions from coal- and oil-fired generating facilities are now subject to Section 112 of the Clean Air Act, which authorizes the EPA to develop standards for the installation of maximum achievable control technology (MACT) to reduce emissions of Hazardous Air Pollutants, including mercury. While the EPA has the authority to develop MACT standards for mercury, it has not yet promulgated such standards. We expect many of our coal-fired facilities to emit less mercury as a result of the SO2 and NOx controls that have been, or soon will be, installed.

NSR Enforcement Initiative. In 2001, the EPA requested information concerning some of our facilities in Maryland and Virginia covering a time period that pre-dates our acquisition or lease of those facilities in December 2000. We responded fully to this request. Under the APSA, Pepco is responsible for fines and penalties arising from any violation associated with operations prior to our subsidiaries acquisition or lease of the facilities. If a violation is determined to have occurred at any of the facilities, our subsidiary owning or leasing the facilities may be responsible for the cost of purchasing and installing emissions control equipment, the cost of which may be material. Our subsidiaries owning or leasing the Chalk Point, Dickerson and Morgantown facilities in Maryland are installing a variety of emissions control equipment at those facilities to comply with the Maryland Healthy Air Act, but that equipment may not include all of the pollution control equipment that could be required if a violation of the EPA s NSR regulations is determined to have occurred at

Table of Contents

one or more of those facilities. If such a violation is determined to have occurred after our subsidiaries acquired or leased the facilities or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, our subsidiary owning or leasing the facility at issue could also be subject to fines and penalties by the state or federal government for the period after its acquisition or lease of the facility, the cost of which may be material, although applicable bankruptcy law may bar such liability for periods prior to January 3, 2006, when the Plan became effective for us and our subsidiaries that own or lease these facilities.

Massachusetts CAIR Implementation. The Commonwealth of Massachusetts Department of Environmental Protection (MADEP) promulgated regulations to take effect in 2009 to reduce NOx emissions from certain generating facilities. The Massachusetts regulations will require our Canal and Kendall generating facilities during the Ozone Season to reduce their emissions of NOx or utilize emissions allowances in amounts greater than they utilized prior to 2009.

New York CAIR Implementation. The NYSDEC promulgated regulations implementing the SO2 and NOx emissions reductions required by the federal CAIR beginning in 2009. Those regulations will limit NOx emissions through both an annual cap-and-trade program and through a seasonal cap-and-trade program during the Ozone Season, which will require our Bowline generating facility to reduce its emissions of NOx by running less or increasing its utilization of emissions allowances. The regulations also provide for an SO2 emissions program beginning in 2010 that will mandate increased utilization of federal SO2 allowances for every ton of SO2 emitted.

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 CAIR. In the fourth quarter of 2007, the Virginia State Air Pollution Control Board approved regulations that it interprets as prohibiting the trading of SO2 and NOx allowances by facilities in non-attainment areas to satisfy the requirements of the CAIR as implemented by Virginia. Our Potomac River facility is located in a non-attainment area for ozone. Thus, this Virginia regulation effectively caps our SO2 and NOx emissions at amounts equal to the allowances allocated to the facility. Mirant Potomac River has appealed these regulations in Virginia state court. In July 2008, the Virginia state court issued a ruling dismissing our appeal, which ruling we have appealed. We have also petitioned (a) the EPA to reconsider and (b) the United States Court of Appeals for the Fourth Circuit (the Fourth Circuit) to review the EPA s final rule approving Virginia s CAIR program.

New York Consent Decree. In 2000, the State of New York issued an NOV to the previous owner of our Lovett facility alleging NSR violations associated with the operation of that facility prior to its acquisition by us. To resolve the issues raised by the State of New York, on June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into the 2003 Consent Decree. Under the 2003 Consent Decree, Mirant Lovett had three options: (1) install emissions controls on Lovett s two coal-fired units (units 4 and 5); (2) shut down unit 4 and convert unit 5 to natural gas; or (3) shut down unit 4 in 2008 and unit 5 in 2007. We concluded that the installation of the required emissions controls was uneconomic. We also concluded that operating unit 5 on natural gas was uneconomic.

On May 10, 2007, Mirant Lovett entered into an amendment to the 2003 Consent Decree with the State of New York that switched the deadlines for shutting down units 4 and 5 so that the deadline for compliance by unit 5 was extended until April 30, 2008, and the deadline for unit 4 was shortened. We discontinued operation of unit 4 as of May 7, 2007. In addition, we discontinued operation of unit 3 because it was uneconomic to run the unit. We shut down unit 5 on April 19, 2008, and have substantially completed the demolition of the Lovett facility.

State 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. One such effort is the RGGI, a multi-state initiative in the Northeast outlining a cap-and-trade program to reduce CO2 emissions from units of 25 MW or greater. The RGGI program calls for signatory states to stabilize CO2 emissions to current levels from 2009 to 2015, followed by a 2.5% reduction each year from 2015 to 2018. Regulations to implement the RGGI have now been approved in each of Maryland, Massachusetts and New York.

Table of Contents

In 2009, we expect to produce approximately 16.6 million tons of CO_2 at our Maryland, Massachusetts and New York generating facilities. The RGGI regulations require those facilities to obtain allowances to emit CO_2 beginning in 2009. No allowances were granted to existing sources of such emissions. Instead, allowances have been made available for such facilities only 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 also provide that if the allowance clearing price exceeds $7 (adjusted by changes in the consumer price index since 2005) per ton of CO_2 in the auctions of allowances that occur during the first three years, 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 zero 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, as adjusted, will be in proportion to each generator s annual average heat input during the period 2003 through 2005 as compared to the total average input for all affected Maryland generators in existence at that time.

The first auction of allowances by the RGGI states was held on September 25, 2008. The clearing price for the approximately 12.5 million allowances sold in the auction was $3.07 per ton. The second auction took place in December 2008, and the clearing price for the approximately 31.5 million allowances sold was $3.38 per ton. The allowances sold in these auctions can be used for compliance in any of the RGGI states. Further auctions will occur on a quarterly basis through 2011.

We are continuing to evaluate our options to comply with the RGGI, but its implementation in Maryland, Massachusetts and New York 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.

In California, emissions of greenhouse gases are governed by the Global Warming Solutions Act (AB 32), which requires that greenhouse gas emissions be reduced to 1990 levels by 2020. AB 32 also requires the California Air Resources Board to develop by January 2009 a greenhouse gas reduction plan for all industrial sectors. In December 2008, the California Air Resource Board approved a plan for implementing AB 32. The plan contemplates a cap-and-trade program, beginning in 2012. AB32, and any plans, rules and programs approved to implement AB 32, could have a material adverse effect on how we operate our California facilities and the costs of operating the facilities.

In August 2008, Massachusetts also adopted the 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 MADEP is to establish a reporting and verification system for statewide greenhouse gas emissions, including emissions from generating facilities producing all electricity consumed in Massachusetts, and to determine what the state s greenhouse gas emissions level was in 1990. The Massachusetts Executive Office of Energy and Environmental Affairs (MAEEA) is then 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 facilities and the costs of operating those facilities.

Federal Regulation of Greenhouse Gases. Various bills have been proposed in Congress to govern CO_2 emissions from generating facilities. Also, 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 may also promulgate regulations regarding the emission of greenhouse gases. Congress or the EPA will likely take action to regulate CO_2 within the next several years. The final form of such regulation will be influenced by political and economic factors and is uncertain at this time. Current proposals include a cap-and-trade system that would require us to purchase allowances for the CO_2 emitted by our generating facilities. While we expect that market prices for electricity would increase following such regulation and would allow us to recover most of the cost of these allowances, we cannot predict with any certainty the actual increases in costs such regulation could impose upon us or our ability to recover such cost increases through higher market rates for electricity, and these regulations could have a material adverse effect on our consolidated statements of operations, financial position or cash flows. We expect to produce approximately 18.3 million tons of CO_2 at all of our generating facilities in 2009.

Water Regulations

We are required under the Clean Water Act to comply with intake and discharge requirements, requirements for technological controls and operating practices. To discharge water, we generally need permits required by the Clean Water Act. Such permits typically are subject to review every five years. As with air quality regulations, federal and state water regulations are expected to impose additional and more stringent requirements or limitations in the future. This is particularly the case for regulatory requirements governing cooling water intake structures, which are subject to regulation under section 316(b) of the Clean Water Act (the 316 (b) regulations). A 2007 decision by the United States Court of Appeals for the Second Circuit (the Second Circuit) in *Riverkeeper Inc. et al v. EPA*, in which the court remanded to the EPA for reconsideration numerous provisions of the EPA s section 316(b) regulations for existing power plants, has created substantial uncertainty about exactly what technologies or other measures will be needed to satisfy section 316(b) requirements in the future and when any new requirements will be imposed. That decision by the Second Circuit is under review by the United States Supreme Court.

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

Mirant and Mirant Delta received two letters, one dated September 27, 2007, sent on behalf of the Coalition for a Sustainable Delta, four water districts, and an individual and the second dated October 16, 2007, sent on behalf of San Francisco Baykeeper (collectively with the parties sending the September 27, 2007, letter, the Noticing Parties), providing notice that the Noticing Parties intend to file suit alleging that Mirant Delta has violated, and continues to violate, the Federal Endangered Species Act through the operation of its Contra Costa and Pittsburg generating facilities. The Noticing Parties contend that the facilities use of water drawn from the Sacramento-San Joaquin Delta for cooling purposes results in harm to four species of fish listed as endangered species. The Noticing Parties assert that Mirant Delta s authorizations to take (i.e., cause harm to) those species, biological opinions and incidental take statements issued by the National Marine Fisheries Service on October 17, 2002, for three of the fish species and the United States Fish and Wildlife Service on November 4, 2002, for the fourth fish species, have been violated by Mirant Delta. Therefore, the notifying parties assert that the authorizations for the effects on the four fish species caused by the operation of the Contra Costa and Pittsburg generating facilities are no longer applicable. Following receipt of these letters, in late October 2007, Mirant Delta received correspondence from the United States Fish and Wildlife Service, the National Marine Fisheries Service and the Army Corps of Engineers clarifying that Mirant Delta continued to be authorized to take the four species of fish protected under the Federal Endangered Species Act. The agencies have initiated a process that will review the environmental effects of Mirant Delta s water usage, including effects on the protected species of fish. That process could lead to changes in the manner in which Mirant Delta can use river water for the operation of the Contra Costa and Pittsburg generating facilities. In a subsequent letter, the Coalition for a Sustainable Delta also alleged violations of the National Environmental Policy Act and the California Endangered Species Act associated with the operation of Mirant Delta s facilities. Mirant Delta disputes the allegations made by the Noticing Parties. No lawsuits have been filed to date, and San Francisco Baykeeper on February 1, 2008, withdrew its notice of intent to sue.

Additionally, in September 2007, Mirant Delta signed an amendment to a Memorandum of Agreement with the California Department of Fish and Game. The amendment requires Mirant Delta to initiate monitoring of the effects on fish of the operations of the Contra Costa and Pittsburg generating facilities, to prepare an environmental impact report, and to submit within 24 months an application for a new permit authorizing Mirant Delta to take the protected fish species affected by the operation of its facilities. The amendment extends Mirant Delta s authorization for take of fish species protected under the California Endangered Species Act until the California Department of Fish and Game completes its consideration of the application for the new permit.

Potrero National Pollution Discharge Elimination System Permit. On June 8, 2006, Bayview-Hunters Point Community Advocates and Communities for a Better Environment filed a petition challenging the issuance of the National Pollution Discharge Elimination System (NPDES) permit for our Potrero facility. On February 8, 2007, Bayview-Hunters Point Community Advocates and Communities for a Better Environment filed another petition with a request to amend their initial petition. On March 21, 2007, the California State Water Resources Control Board notified the parties that petitioners requested that as of March 19, 2007, the two petitions be moved from active status to abeyance. Those petitions currently remain in abeyance. Additionally, on June 15, 2007, Bayview-Hunters Point Community Advocates and Communities for a Better Environment and San Francisco Baykeeper filed a third petition requesting that the NPDES permits for Potrero and Mirant Delta s Pittsburg facility be reopened. The State Water Resources Control Board denied that petition on November 27, 2007.

Kendall NPDES and Surface Water Discharge Permit. On September 26, 2006, the EPA issued to Mirant Kendall an NPDES renewal permit for the Kendall generating facility. The same permit was concurrently issued by the MADEP as a state Surface Water Discharge Permit (SWD Permit), and was accompanied by MADEP s earlier issued water quality certificate under section 401 of the Clean Water Act. The new permits impose new temperature limits at various points in the Charles River, an extensive temperature, water quality and biological monitoring program and a requirement to develop and install a barrier net system to reduce fish impingement and entrainment. The provisions regulating the thermal discharge could cause substantial curtailments of the operations of the Kendall facility. Mirant Kendall has appealed the permits in three proceedings: (1) appeal of the NPDES permit to the EPA s Environmental Appeals Board; (2) appeal of the SWD Permit to the MADEP; and (3) appeal of the water quality certification to the MADEP. The effect of the permits has been stayed pending the outcome of these appeals. The two appeals to the MADEP have been stayed pending the outcome of the appeal to the Environmental Appeals Board. On September 28, 2007, the Environmental Appeals Board stayed the appeal proceedings until April 18, 2008, in order for the EPA to address the sections of the permit that are affected by the EPA s suspension of the 316(b) regulations as a result of the 2007 decision by the Second Circuit in *Riverkeeper, Inc. et al. v. EPA.* Subsequent orders by the Environmental Appeals Board have extended that stay to March 6, 2009. On March 6, 2008, the EPA and the MADEP issued a draft permit modification to address the 316(b) provisions of the permit that would require modifications to the intake structure for the Kendall generating facility to add fine and coarse mesh barrier exclusion technologies and to install a mechanism to sweep organisms away from the intake structure through an induced water flow. On May 1, 2008, Mirant

Table of Contents

Kendall submitted comments on the draft permit modification objecting to the new requirements. On December 19, 2008, the EPA and the MADEP issued final permit modifications to address the 316(b) regulations. Those final permit modifications did not substantially modify the requirements proposed in the draft modifications, and on February 2, 2009 Mirant Kendall filed an appeal of those modifications. While the appeals are pending, the effect of any contested permit provisions will be stayed and the Kendall generating facility will continue to operate under its current NPDES permit. We are unable to predict the outcome of these proceedings.

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

NPDES and State Pollutant Discharge Elimination System Permit Renewals. In addition to the proceedings described above in *Kendall NPDES and Surface Water Discharge Permit* and *Canal NPDES and SWD Permit* related to the renewal of the NPDES permit for the Kendall and Canal facilities, proceedings are currently pending for renewal of the NPDES permits for the Dickerson and Morgantown facilities leased by Mirant Mid-Atlantic, the Chalk Point facility owned by Mirant Chalk Point, three ash sites in Maryland owned by Mirant MD Ash Management, the Potomac River facility owned by Mirant Potomac River, the Contra Costa and Pittsburg facilities owned by Mirant Delta and the Potrero facility owned by Mirant Potrero. A proceeding is also pending for renewal of the State Pollutant Discharge Elimination System (SPDES) permit for the Bowline facility owned by Mirant Bowline.

In general, the EPA and the state agencies responsible for implementing the provisions of the Clean Water Act applicable to the intake of water and discharge of effluent by electric generating facilities have been making the requirements imposed upon such facilities more stringent over time. For example, with respect to the Potrero facility, the California Regional Water Quality Control Board has previously stated its intent not to renew the facility s NPDES permit unless Mirant Potrero can demonstrate that the operation of the facility does not adversely affect the San Francisco Bay. With respect to each of these permit renewal proceedings, the permit renewal proceeding could take years to resolve and the agency or agencies involved could impose requirements upon the Mirant entity owning the facility that require significant capital expenditures, limit the times at which the facility can operate, or increase operations and maintenance costs materially.

Wastes, Hazardous Materials and Contamination

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

In November 2008, the MDE promulgated new regulations to govern the handling, storage, recycling and disposal of coal combustion byproducts in Maryland. We have challenged portions of these new regulations in state court because they do not provide adequate time for effectuating the required changes to our facilities and they are unclear in many respects.

Additionally, CERCLA, also known as the Superfund law, establishes a federal framework for dealing with the cleanup of contaminated sites. Many states have enacted similar state superfund statutes as well as other laws imposing obligations to investigate and clean up contamination. Our Contra Costa, Pittsburg and Potrero facilities have areas of soil and groundwater contamination subject to CERCLA and the California Health and Safety Code. In 1998, prior to our acquisition of those facilities from PG&E, consultants for PG&E conducted soil and groundwater investigations at those facilities which revealed contamination. The consultants conducting the investigation estimated the aggregate cleanup costs at those facilities could be as much as $60 million. Pursuant to the terms of the Purchase and Sale Agreement with PG&E, PG&E has responsibility for the containment or capping of all soil and groundwater contamination and the disposition of up to 60,000 cubic yards of contaminated soil from the Potrero generating facility and the remediation of any groundwater or solid contamination identified by PG&E s consultants in 1998 at the Contra Costa and Pittsburg generating facilities, before those facilities were purchased in 1999 by our subsidiaries. Pursuant to our requests, PG&E has disposed of 807 cubic yards of contaminated soil from the Potrero generating facility. We are not aware of soil or groundwater conditions for which we expect remediation costs to be material that are not the responsibility of other parties.

Table of Contents

Employees

At December 31, 2008, we employed 1,661 people, which included approximately 1,146 employees at our generating facilities, 62 employees at our regional offices and 453 employees at our corporate headquarters in Atlanta, Georgia. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
Mid-Atlantic Region			
IBEW Local 1900	Maryland and Virginia	530	6/1/2010
Northeast Region			
IBEW Local 503[(1)]	New York	49	4/30/2013
UWUA Local 369[(2)]	Cambridge, Massachusetts	34	2/28/2009
UWUA Local 480	Sandwich, Massachusetts	46	6/1/2011
California			
IBEW Local 1245	California	118	10/31/2013
Total		777	

(1) Our previous contract with Local 503 expired on June 1, 2008. After reaching an impasse in negotiations with Local 503, on January 28, 2009, we unilaterally implemented the terms of our final offer to the union. Bargaining unit employees have continued to work under the terms imposed by us without disruption.

(2) We are currently in negotiations with Local 369 on new agreements.

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

Table of Contents

Item 1A. *Risk Factors*

The following are factors that could affect our future performance:

Our revenues are unpredictable because most of our 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 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. Being concentrated in a few geographic markets results in concentrated exposure to those markets, especially PJM. 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 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 possibility that the appellate court considering the pending appeal of the FERC s rulings that approved the RPM provisions of PJM s tariff does not affirm the FERC s approval of those provisions, resulting in modifications to the capacity payments made under that tariff in the future and possibly refunds for past periods;
- 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 supplies 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;
- 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 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.

The global financial crisis may have an effect on our business and financial condition in ways that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system has had and may continue to have an effect on our business and our financial condition. 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, we expect that the total availability under our senior secured revolving credit facility has decreased from $800 million to $755 million, assuming that Lehman Commercial Paper, Inc. does not honor its $45 million commitment. While we do not expect that the Lehman Commercial Paper, Inc. bankruptcy will have a material adverse effect on Mirant, the 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 7.   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, the credit crisis could have a negative effect on our ability to obtain new lines of credit if financial institutions are unwilling or unable to enter into new revolving credit facilities.

In addition to the potential effect on our liquidity that could arise from the global financial crisis, the crisis could have a negative effect on the markets in which we sell power, purchase fuel and perform other trading and marketing activities. In recent years, global financial institutions have been active participants in such markets. As such financial institutions consolidate and operate under more restrictive capital constraints in response to the 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 addition, 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. Deterioration in the financial condition of our counterparties as a result of the global financial crisis and the 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.

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

Our generating facilities in California depend almost entirely on payments in support of system reliability. The energy market, as currently constituted, will not justify the capital expenditures necessary to repower or reconstruct 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 generating facilities will be commercially viable only as long as they are necessary for reliability.

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, crude oil and coal, natural disasters, wars, embargoes and other catastrophic events, and federal, state and environmental regulation and legislation. 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. Specifically, significant fluctuations in the price of coal may affect the financial position of the coal suppliers with which we have contracted. In addition, significant fluctuations in the price of natural gas may cause significant fluctuations in the price of electricity.

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. Unauthorized hedging and related activities by our employees 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.

We are exposed to the risk of fuel and fuel transportation cost increases and volatility and interruption in fuel supply because our 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.

The average market price for the types of coal that we use was approximately 107% higher in the year ended December 31, 2008, than in 2007. Global demand for coal to generate electricity has been a significant factor influencing domestic prices for the types of coal that we use. At the same time, the prices for power and natural gas were extremely volatile, increasing during the first half of 2008 and decreasing during the second half of 2008. Fluctuations in natural gas prices have a significant effect on the price of power, especially in the PJM market where the marginal price for power is often set by gas-fired units. In 2008 as compared to 2007, the energy gross margin earned from our baseload coal units was negatively affected by contracting dark spreads, the difference between the price received for electricity generated compared to the market price of the coal required to produce the electricity. In the fourth quarter of 2008 and in early 2009, the average market price for the types of coal that we use declined from the highs observed earlier in 2008. However, the average market price for power also declined during the same period.

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 coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2013.

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 SFAS 133. None of our derivatives recorded at fair value are designated as hedges under SFAS 133 and changes in their fair values are therefore recognized currently 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. For a more detailed discussion of the accounting treatment of our asset management, proprietary trading and fuel oil management activities, see Note 4 to our consolidated financial statements contained elsewhere in this report.

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);
- restrictions on emissions;
- 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;

Table of Contents

- 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.

If our facilities experience unplanned outages, we may be required to procure replacement power in the open market to satisfy contractual commitments. If we should lack adequate liquidity to post margin and collateral requirements, we may be exposed to significant losses and may miss significant opportunities, and we may have increased exposure to the volatility of spot markets.

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.

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 impact on the revenues generated by our facilities.

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, wastewater discharge and cooling water systems, are generally becoming more stringent, which may require us to make additional facility upgrades or restrict our operations.

Table of Contents

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 taxes or purchases of emissions allowances. 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. Because our generating facilities emit CO2, these regulations and similar future laws may significantly increase our operating costs.

Certain environmental laws, including CERCLA and comparable state laws, impose strict and, in many circumstances, joint and several liability for costs of remediating contamination in soil, groundwater and elsewhere. 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.

Major environmental construction projects planned by 2010 at our Mid-Atlantic coal facilities may not meet their anticipated schedule, which would restrict these units from running at their maximum economic levels. If the operating constraints were sufficiently severe, Mirant Mid-Atlantic may not have sufficient cash flow to permit it to make distributions or, if more severe, to meet its obligations.

Under the Maryland Healthy Air Act, we are required to reduce annual emissions below certain levels by January 2010. The levels established do not allow for the use of emissions allowances to meet the mandated levels. To meet these requirements, we are installing pollution control equipment on all of our Maryland coal-fired units. We may not have completed installation of or be able to operate this pollution control equipment by January 2010 because of a number of factors, including:

- adverse weather conditions;
- unanticipated cost increases;
- engineering problems;
- construction problems;
- failure or delays in obtaining necessary permits and approvals;
- shortages of equipment, materials or skilled labor;
- unscheduled delays in delivery of materials and equipment; and
- work stoppages.

Any of these factors may significantly increase the estimated costs of our environmental construction projects or result in a loss of cash flows from operations because of reduced unit operations.

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

We expect that certain of our generating facilities and related properties will become 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.

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 December 31, 2008, our consolidated indebtedness was $2.676 billion. In addition, the present value of lease payments under the Mirant Mid-Atlantic leveraged leases is approximately $1.0 billion (assuming a 10% discount rate) and the termination value of the Mirant Mid-Atlantic leveraged leases is $1.4 billion. Our leverage and obligations under the leveraged leases could have important consequences, including the following: (1) it 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 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 more 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) it 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.

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 operation or curtailment 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 will 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 transaction 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.

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. See Item 7. Management s Discussion and Analysis Liquidity and Capital Resources for a discussion of restrictions on the ability of Mirant North America to make distributions to its parent, Mirant Americas Generation.

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 December 31, 2008, we had approximately $111 million of posted cash collateral and $301 million of letters of credit outstanding primarily to support our asset management activities, debt service and rent reserve requirements and other commercial arrangements. See Note 10 to our consolidated financial statements contained elsewhere in this report for further information on our posted cash collateral and letters of credit. While 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.

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 costs of operating our facilities or our ability to operate our facilities. Such costs, in turn, may negatively affect our results of operations and financial condition.

We are subject to regulation by the FERC regarding the terms and conditions of wholesale service and rates, 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 where market-based rate authority has been granted, the FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, where 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.

Table of Contents

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. We cannot provide assurance that the introductions of new laws, or other future regulatory developments, will not have a material adverse impact on our business, operations or financial condition.

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 power generators, we face heightened risk of an act of terrorism, either a direct act against one of our generating facilities or an inability to operate as a result of systemic damage resulting from an act against the transmission and distribution infrastructure that is used to transport our power. If such an attack 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.

Table of Contents

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 this Form 10-K. 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.

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

None.

Table of Contents

Item 2. ***Properties***

The properties below were owned or leased as of December 31, 2008. Our leasehold or ownership interest is 100% for each property.

Generating Facilities	Location	Dispatch Type	Primary Fuel	Total MW(1)	2008 Net Capacity Factor
Mid-Atlantic Region:					
Chalk Point	Maryland	Intermediate/Baseload/ Peaking	Natural Gas/Coal/Oil	2,413	21%
Dickerson	Maryland	Baseload/Peaking	Natural Gas/Coal/Oil	849	37%
Morgantown	Maryland	Baseload/Peaking	Coal/Oil	1,486	53%
Potomac River	Virginia	Intermediate/Baseload	Coal	482	19%
Total Mid-Atlantic				5,230	33%
Northeast Region:					
Canal	Massachusetts	Intermediate	Natural Gas/Oil	1,126	17%
Kendall	Massachusetts	Baseload/Peaking	Natural Gas/Oil	256	39%
Martha s Vineyard	Massachusetts	Peaking	Diesel	14	3%
Bowline	New York	Intermediate/Peaking	Natural Gas/Oil	1,139	2%
Total Northeast				2,535	13%
California:					
Contra Costa	California	Intermediate	Natural Gas	674	3%
Pittsburg	California	Intermediate	Natural Gas	1,311	2%
Potrero	California	Intermediate/Peaking	Natural Gas/Diesel	362	17%
Total California				2,347	4%
Total Operations				10,112	21%

(1) Total MW amounts reflect nominal net summer capacity for 2008.

We also own an oil pipeline, which is approximately 51.5 miles long and serves the Chalk Point and Morgantown generating facilities.

Item 3. ***Legal Proceedings***

See Note 16 to our consolidated financial statements contained elsewhere in this report for discussion of the material legal proceedings to which we are a party.

Item 4. ***Submission of Matters to a Vote of Security Holders***

None.

34

Table of Contents

PART II

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

Common Stock

All shares of Old Mirant s common stock were cancelled on January 3, 2006, and 276.5 million shares of New Mirant common stock were distributed to holders of unsecured claims and equity securities. In addition, we reserved 23.5 million shares for unresolved claims, of which approximately 850,000 shares had not yet been distributed as of December 31, 2008. New Mirant is authorized to issue 1.5 billion shares of common stock having a par value of $.01 per share and 100 million shares of preferred stock having a par value of $.01 per share. On January 3, 2006, New Mirant also issued Series A Warrants and Series B Warrants, expiring January 3, 2011, which entitled their holders to purchase, as of that date, an aggregate of 35.3 million and 17.6 million shares of common stock, respectively. The exercise price of the Series A Warrants and Series B Warrants is $21.87 and $20.54 per share, respectively. There were approximately 26.9 million Series A Warrants and 7.1 million Series B Warrants outstanding at December 31, 2008.

All of the New Mirant common stock was issued in accordance with Section 1145 of the Bankruptcy Code, and we received no proceeds from such issuance. The issuance of shares of New Mirant common stock was exempt from the registration requirements of the Securities Act, as amended, and equivalent provisions of state securities laws, in reliance upon Section 1145(a) of the Bankruptcy Code.

Our common stock is currently traded on the NYSE under the ticker symbol MIR. We have submitted to the NYSE our 2008 annual certificate from our Chief Executive Officer certifying that he is not aware of any violation by the Company of NYSE corporate governance listing standards. The closing price of our stock on December 31, 2008, was $18.87. The following table sets forth the high and low prices for our common stock as reported by the NYSE for the periods indicated.

Price Range of Common Stock

Quarter	High	Low
2007		
First	$ 41.70	$ 30.41
Second	$ 49.00	$ 39.61
Third	$ 44.20	$ 34.77
Fourth	$ 44.61	$ 36.20
2008		
First	$ 39.53	$ 33.75
Second	$ 42.21	$ 36.08
Third	$ 39.20	$ 17.32
Fourth	$ 20.28	$ 11.99

Holders

As of January 31, 2009, there were approximately 58,770 record holders of our common stock, par value $.01 per share.

Dividends

We have not paid or declared any cash dividends on our common stock in the last two fiscal years and we do not anticipate paying any quarterly cash dividends in the foreseeable future.

Table of Contents

Return of Cash

On November 9, 2007, we announced that we planned to return a total of $4.6 billion of excess cash to our stockholders based on four factors: (1) the outlook for the business, (2) preserving our credit profile, (3) maintaining adequate liquidity, including for capital expenditures and (4) maintaining sufficient working capital. On September 22, 2008, we announced that we had returned $3.856 billion of cash to our stockholders and suspended our program to return excess cash to our stockholders based on our evaluation of the four factors that were set out upon commencement of the share repurchase program. On November 7, 2008, we announced that we were resuming our program of returning excess cash to our stockholders and would purchase an additional $200 million of shares through open market purchases. This $200 million was completed in the fourth quarter of 2008 and was in addition to the previous $3.856 billion of cash returned to our stockholders.

On November 9, 2007, we announced that the first stage of the cash distribution would be accomplished through an accelerated share repurchase program for $1 billion, plus open market purchases for up to an additional $1 billion. In the fourth quarter of 2007, we repurchased 26.66 million shares of common stock for $1 billion through the accelerated share repurchase program.

On February 29, 2008, we announced that we had decided to return the remaining $2.6 billion of cash through open market purchases of common stock but that we would continue to evaluate the most efficient method to return the cash to stockholders.

On May 15, 2008, the accelerated share repurchase program was completed and we received an additional 682,387 shares, resulting in a total of 27.34 million shares purchased. The final price of shares repurchased under the accelerated share repurchase program was $36.57 per share, which was determined based on a discount to the volume weighted average trading price of our common stock over the period of the accelerated share repurchase program.

Between November 2007 and December 2008, we returned approximately $4.056 billion of cash to our stockholders through purchases of 122 million shares of our common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion. We have repurchased approximately 48% of the 256 million basic shares that we had outstanding when the program began in November 2007.

Share Repurchases

The following table sets forth information regarding repurchases by us of our common shares on the NYSE during the three-month period ended December 31, 2008:

Period	Shares repurchased (in millions)	Average price paid per share	Total number of shares purchased as part of publicly announced plans (in millions)	Approximate dollar value of shares that may yet be purchased under the plans (in millions)
Oct 1, 2008 Oct 31, 2008		$		$
Nov 1, 2008 Nov 30, 2008	10.46	$ 16.57	10.46	$ 26.71
Dec 1, 2008 Dec 31, 2008	1.48	$ 18.04	1.48	$
Total	11.94		11.94	

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth the compensation plans under which our equity securities were authorized for issuance as of December 31, 2008:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (in millions)	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities to be issued upon exercise of outstanding options, warrants and rights) (in millions)
Equity compensation plans approved by security holders	6.3	$ 29.46	12.3
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	6.3	$ 29.46	12.3

Our 2005 Omnibus Incentive Plan for certain employees and directors of Mirant became effective on January 3, 2006, and is deemed to have been approved by our stockholders by virtue of its approval under the Plan.

Stock Performance Graph

The performance graph below is being provided as furnished and not filed as permitted by 17 Code of Federal Regulations 229.201(e), in this Form 10-K and compares the cumulative total stockholder return on our common stock with the Standard & Poor s 500 Index, the Standard & Poor s Multi-Utility Index and the Standard & Poor s Independent Power Producers and Energy Traders Index since the re-issuance of our common stock in connection with our emergence from bankruptcy on January 3, 2006. Our stock was re-listed on the NYSE on January 11, 2006. Because all of Old Mirant s outstanding common stock was cancelled upon emergence from bankruptcy, stock performance prior to 2006 does not provide a meaningful comparison for current stockholders and thus has not been provided. The graph assumes that $100 was invested on January 11, 2006, in our common stock and each of the above indices, and that all dividends are reinvested. The stockholder return shown below may not be indicative of future performance.

Indexed Returns

Year Ended

Company / Index	12/31/2006	12/31/2007	12/31/2008
Mirant	$ 126.38	$ 156.04	$ 75.54
S&P 500 Index	$ 111.69	$ 117.82	$ 74.23
S&P 500 Multi-Utilities Index	$ 115.41	$ 127.95	$ 96.80
S&P 500 Independent Power Producers & Energy Traders	$ 125.03	$ 157.71	$ 48.70

Total Return to Stockholders

(Includes reinvestment of dividends)

Annual Return Percentage

Year Ended

Company / Index	12/31/2006	12/31/2007	12/31/2008
Mirant	26.38%	23.47%	(51.59)%
S&P 500 Index	11.69%	5.49%	(37.00)%
S&P 500 Multi-Utilities Index	15.41%	10.86%	(24.34)%
S&P 500 Independent Power Producers & Energy Traders	25.03%	26.13%	(69.12)%

Table of Contents

Item 6. ***Selected Financial Data***

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

	Years Ended December 31, (in millions except per share data)				
	2008	2007	2006	2005	2004
Statements of Operations Data:					
Operating revenues	$ 3,188	$ 2,019	$ 3,087	$ 2,620	$ 3,231
Income (loss) from continuing operations	1,215	433	1,752	(1,385)	(9)
Income (loss) from discontinued operations	50	1,562	112	93	(467)
Cumulative effect of changes in accounting principles				(15)	
Net income (loss)	1,265	1,995	1,864	(1,307)	(476)
Basic EPS per common share from continuing operations	$ 6.53	$ 1.72	$ 6.15	N/A	N/A

Our Statement of Operations Data for each year reflects the volatility caused by unrealized gains and losses related to derivative financial instruments used to hedge electricity and fuel economically. 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 consolidated statements of operations. Changes in the fair value and settlements of derivative financial instruments for proprietary trading and fuel oil management activities are recorded on a net basis as operating revenue in the accompanying consolidated statements of operations. See Note 4 to our consolidated financial statements contained elsewhere in this report for additional information.

	Years Ended December 31, (in millions)				
	2008	2007	2006	2005	2004
Unrealized gains (losses) included in operating revenues	$ 840	$ (564)	$ 757	$ (92)	$ 176
Unrealized losses (gains) included in cost of fuel, electricity and other products	54	(28)	102	(76)	8
Total	$ 786	$ (536)	$ 655	$ (16)	$ 168

Our Statement of Operations Data for the year ended December 31, 2007, reflects gains on sales of discontinued operations as discussed in Note 11 to our consolidated financial statements contained elsewhere in this report. EPS information for years prior to 2006 has not been presented because the information is not relevant in any material respect for users of our financial statements. See Note 13 to our consolidated financial statements contained elsewhere in this report for additional information. Our Statement of Operations Data for the year ended December 31, 2006, reflects significant income tax benefits as discussed in Note 7 to our consolidated financial statements contained elsewhere in this report.

Our Statement of Operations Data for the year ended December 31, 2005, reflects the effects of accounting for the Plan confirmed on December 9, 2005. During our bankruptcy proceedings, our consolidated financial statements were prepared in accordance with SOP 90-7. Our Statement of Operations Data for the year ended December 31, 2004, does not include interest expense on debt that was subject to compromise subsequent to the Petition Date and includes goodwill impairment losses of $582 million.

Table of Contents

The consolidated Balance Sheet Data for years 2006, 2005 and 2004, segregates pre-petition liabilities subject to compromise from those liabilities that were not subject to compromise.

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions)				
Balance Sheet Data:					
Total assets	$ 10,688	$ 10,538	$ 12,845	$ 14,364	$ 11,926
Total long-term debt	2,676	3,095	3,275	2,582	38
Liabilities subject to compromise			18	18	9,164
Stockholders equity (deficit)	$ 3,762	$ 5,310	$ 4,443	$ 3,856	$ (1,318)

The debt of Mirant Americas Generation that was reinstated in 2005 is included in liabilities subject to compromise for 2004. In 2005, we recorded the effects of the Plan. As a result, liabilities subject to compromise at December 31, 2005 and 2006, only reflect the liabilities of our New York entities that remained in bankruptcy at that time. Total assets for all periods reflect our election in 2008 to discontinue the net presentation of assets subject to master netting agreements upon adoption of FSP FIN 39-1.

Table of Contents

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

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

Overview

We are a competitive energy company that produces and sells electricity in the United States. We own or lease 10,112 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.

Share Repurchases

Between November 2007 and December 2008, we returned approximately $4.056 billion of cash to our stockholders through purchases of 122 million shares of our common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion. We have repurchased approximately 48% of the 256 million basic shares that we had outstanding when the program began in November 2007. See Note 13 to our consolidated financial statements contained elsewhere in this report for additional information related to our share repurchases.

Hedging Activities

We hedge economically a substantial portion of our Mid-Atlantic coal-fired baseload generation and certain of our 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. A significant portion 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 February 10, 2009, our aggregate hedge levels based on expected generation for each period were as follows:

	Aggregate Hedge Levels Based on Expected Generation				
	2009	**2010**	**2011**	**2012**	**2013**
Power	96%	62%	22%	24%	24%
Fuel	90%	64%	53%	29%	6%

Capital Expenditures and Capital Resources

Including amounts already spent to date, we expect to incur total capital expenditures of $1.674 billion to comply with the limitations on SO2, NOx and mercury emissions under the Maryland Healthy Air Act. As of December 31, 2008, we have paid approximately $997 million for capital expenditures related to the Maryland Healthy Air Act. For the year ended December 31, 2008, we paid $683 million for capital expenditures, excluding capitalized interest, of which $497 million related to the Maryland Healthy Air Act. The following table details the expected timing of payments for our estimated capital expenditures, excluding capitalized interest, for 2009 and 2010 (in millions):

	2009	**2010**
Maryland Healthy Air Act	$ 490	$ 187
Other environmental	33	33
Maintenance	162	132
Construction	55	55
Other	14	15
Total	$ 754	$ 422

41

Table of Contents

We expect that available cash and future cash flows from operations will be sufficient to fund these capital expenditures.

Consolidated Financial Performance

We reported net income of $1.265 billion, $1.995 billion and $1.864 billion for the years ended December 31, 2008, 2007 and 2006, respectively. The change in net income is detailed as follows (in millions):

	Years Ended December 31,					
	2008	2007	Increase/ (Decrease)	2007	2006	Increase/ (Decrease)
Realized gross margin	$ 1,343	$ 1,643	$ (300)	$ 1,643	$ 1,281	$ 362
Unrealized gross margin	786	(536)	1,322	(536)	655	(1,191)
Total gross margin	2,129	1,107	1,022	1,107	1,936	(829)
Operating Expenses:						
Operations and maintenance	683	707	(24)	707	592	115
Depreciation and amortization	144	129	15	129	137	(8)
Impairment losses		175	(175)	175	119	56
Gain on sales of assets, net	(39)	(45)	6	(45)	(49)	4
Total operating expenses	788	966	(178)	966	799	167
Operating income	1,341	141	1,200	141	1,137	(996)
Total other expense (income), net	124	(299)	423	(299)	99	(398)
Income from continuing operations before reorganization items, net and income taxes	1,217	440	777	440	1,038	(598)
Reorganization items, net		(2)	2	(2)	(164)	162
Provision (benefit) for income taxes	2	9	(7)	9	(550)	559
Income from continuing operations	1,215	433	782	433	1,752	(1,319)
Income from discontinued operations	50	1,562	(1,512)	1,562	112	1,450
Net income	$ 1,265	$ 1,995	$ (730)	$ 1,995	$ 1,864	$ 131

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, and realized gross margin separately from unrealized gross margin in order to be consistent with how we manage our business. Therefore, it may not be possible to compare our non-GAAP financial measures with those of other companies which also present similar non-GAAP financial measures. We encourage our investors to review our consolidated financial statements and other publicly filed reports in their entirety and not to rely on a single financial measure.

Commodity Prices

The prices for power, natural gas and fuel oil were extremely volatile during 2008. For the year ended December 31, 2008, we recognized unrealized gains of $786 million. We are generally economically neutral for that portion of the portfolio that we have hedged because our realized gross margin will reflect the contractual prices of our power and fuel contracts.

Our coal supply comes primarily from the Central Appalachian and Northern Appalachian coal regions. The average market price for the types of coal that we use was approximately 107% higher in the year ended December 31, 2008, than in the same period in 2007. Global demand for coal to generate electricity was a significant factor influencing domestic prices for the types of coal that we use. Coal prices in other regions did not increase as dramatically; however, switching the types of coal that we use would require significant capital expenditures and increases in transportation costs. As a result of the increases in market prices, the energy gross margin earned from our baseload coal units was negatively affected by contracting dark spreads, the difference

Table of Contents

between the price received for electricity generated compared to the market price of the coal required to produce the electricity. In the fourth quarter of 2008 and in early 2009, the average market price for the types of coal that we use declined from the highs observed earlier in 2008. However, the average market price for power also declined during the same period. 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 coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2013. Most of our coal contracts are not required to be recorded at fair value under SFAS 133. As such, these contracts are not included in derivative contract assets and liabilities in the accompanying consolidated balance sheets. As of December 31, 2008, the net fair value of these long-term coal agreements was approximately $38 million.

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 facilities. The Northeast region includes our Bowline, Canal, Kendall, Lovett (shutdown on April 19, 2008) and Martha s Vineyard facilities. The California region includes our Contra Costa, Pittsburg and Potrero facilities. Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest on debt at Mirant Americas Generation and Mirant North America and interest on our invested cash balances. For the years ended December 31, 2007 and 2006, Other Operations also includes gains and losses related to the Back-to-Back Agreement with Pepco, which was terminated pursuant to a settlement agreement that became effective in the third quarter of 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Pepco Settlement Agreement.

Operating Statistics

The following table summarizes Net Capacity Factor by region for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,					
	2008	**2007**	**Decrease**	**2007**	**2006**	**Increase/ (Decrease)**
Mid-Atlantic	33%	37%	(4)%	37%	36%	1%
Northeast	13%	22%	(9)%	22%	18%	4%
California	4%	4%	%	4%	6%	(2)%
Total	21%	25%	(4)%	25%	24%	1%

Table of Contents

The following table summarizes power generation volumes by region for the years ended December 31, 2008, 2007 and 2006 (in gigawatt hours):

	Years Ended December 31,		Increase/ (Decrease)	Increase/ (Decrease) %	Years Ended December 31,		Increase/ (Decrease)	Increase/ (Decrease) %
	2008	2007			2007	2006		
Mid-Atlantic:								
Baseload	14,350	15,390	(1,040)	(7)%	15,390	15,662	(272)	(2)%
Intermediate	489	1,105	(616)	(56)%	1,105	736	369	50%
Peaking	160	337	(177)	(53)%	337	210	127	60%
Total Mid-Atlantic	14,999	16,832	(1,833)	(11)%	16,832	16,608	224	1%
Northeast:								
Baseload	1,131	2,691	(1,560)	(58)%	2,691	2,757	(66)	(2)%
Intermediate	1,919	2,814	(895)	(32)%	2,814	1,896	918	48%
Peaking	5	5		%	5	15	(10)	(67)%
Total Northeast	3,055	5,510	(2,455)	(45)%	5,510	4,668	842	18%
California:								
Intermediate	868	804	64	8%	804	1,102	(298)	(27)%
Peaking	21	18	3	17%	18	34	(16)	(47)%
Total California	889	822	67	8%	822	1,136	(314)	(28)%
Total Mirant	18,943	23,164	(4,221)	(18)%	23,164	22,412	752	3%

The decrease in power generation volumes for the year ended December 31, 2008, as compared to the year ended December 31, 2007, is primarily the result of the following:

- a decrease in Mid-Atlantic as a result of contracting dark spreads, lower demand and second quarter 2008 planned outages to allow for the installation of emissions control equipment as part of our compliance with the Maryland Healthy Air Act.

- a decrease in Northeast as a result of higher fuel prices at times making it uneconomic for certain units to generate, the shutdown of units 3 and 4 of the Lovett generating facility in April 2007 and the shutdown of unit 5 of the Lovett generating facility in April 2008.

The increase in power generation volumes for the year ended December 31, 2007, as compared to the year ended December 31, 2006, is primarily the result of the following:

- an increase in Mid-Atlantic intermediate and peaking generation volumes as a result of favorable spreads between the cost of oil used to generate one MWh of electricity and the market value of the electricity generated (oil conversion spreads) in 2007 as compared to 2006.

- an increase in Northeast intermediate generation as a result of increased demand in 2007.

Through the end of 2006, the majority of our California units were subject to RMR arrangements with the CAISO. Since that time, all of 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. All of the Potrero units continue to be subject to RMR arrangements. Therefore, changes in power generation volumes from those facilities, which can be caused by weather, planned outages, or other factors, do not generally affect our gross margin.

Table of Contents

2008 versus 2007

Gross Margin Overview

The following table details realized and unrealized gross margin by operating segments (in millions):

	Years Ended December 31,					
	2008			2007		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Mid-Atlantic	$ 1,038	$ 676	$ 1,714	$ 1,084	$ (479)	$ 605
Northeast	189	(10)	179	280	(43)	237
California	127		127	135		135
Other Operations	(17)	120	103	126	(14)	112
Eliminations	6		6	18		18
Total	$ 1,343	$ 786	$ 2,129	$ 1,643	$ (536)	$ 1,107

Gross margin for the years ended December 31, 2008 and 2007, is further detailed as follows (in millions):

	Year Ended December 31, 2008					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 517	$ 73	$ 4	$ (17)	$ 6	$ 583
Contracted and capacity	340	90	123			553
Realized value of hedges	181	26				207
Total realized gross margin	1,038	189	127	(17)	6	1,343
Unrealized gross margin	676	(10)		120		786
Total gross margin	$ 1,714	$ 179	$ 127	$ 103	$ 6	$ 2,129

	Year Ended December 31, 2007					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 686	$ 128	$ 3	$ 109	$ 18	$ 944
Contracted and capacity	196	87	132	17		432
Realized value of hedges	202	65				267
Total realized gross margin	1,084	280	135	126	18	1,643
Unrealized gross margin	(479)	(43)		(14)		(536)
Total gross margin	$ 605	$ 237	$ 135	$ 112	$ 18	$ 1,107

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. For the year ended December 31, 2007, contracted and capacity also included the Back-to-Back Agreement, which was terminated on August 10, 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Pepco Settlement Agreement.

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 our coal supply contracts. 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 that are recorded as derivative contract assets and liabilities on our consolidated balance sheets, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

Our gross margin for the year ended December 31, 2008, was $2.129 billion as compared to $1.107 billion for the same period in 2007. The increase in gross margin, which includes net unrealized gains and losses from our hedging activities, was principally a result of the following:

An increase of $1.322 billion in unrealized gross margin was comprised of the following:

- unrealized gains of $786 million in 2008, which include a $460 million net increase in the value of hedge contracts for future periods primarily related to changes in forward power and natural gas prices in 2008 and $326 million from the settlement of power and fuel contracts during the period for which net unrealized losses had been recorded in prior periods; and

- unrealized losses of $536 million in 2007, which include $438 million from the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and a $98 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices in 2007.

A decrease of $300 million in realized gross margin primarily attributable to:

- a decrease in energy of $361 million as a result of an increase in fuel prices, lower generation volumes and a decrease in the contribution of proprietary trading and fuel oil management activities, partially offset by an increase in power prices and a decrease in the cost of emissions allowances;

- a decrease of $60 million in realized value of hedges as a result of a decrease in the settlement value of power hedges, reduced by an increase in the amount by which market prices for coal exceeded the contract prices for the coal that we purchased under our long-term agreements; partially offset by

- an increase in contracted and capacity of $121 million primarily resulting from a full year of PJM RPM capacity payments in 2008 in the Mid-Atlantic. The contracted and capacity gross margin for 2007 includes a refund to us of $36 million for payments made under the Back-to-Back Agreement for periods after May 31, 2006, as a result of the Pepco Settlement Agreement becoming fully effective in August 2007.

Mid-Atlantic

Our Mid-Atlantic segment, which accounts for approximately 50% of our net generating capacity, includes four generating facilities with total net generating capacity of 5,230 MW.

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

	Years Ended December 31,		Increase/
	2008	2007	(Decrease)
Realized gross margin	$ 1,038	$ 1,084	$ (46)
Unrealized gross margin	676	(479)	1,155
Total gross margin	1,714	605	1,109
Operating Expenses:			

Operations and maintenance	412	360	52
Depreciation and amortization	92	81	11
Gain on sales of assets, net	(8)		(8)
Total operating expenses	496	441	55
Operating income	1,218	164	1,054
Total other expense (income), net	1	(5)	6
Income from continuing operations before reorganization items, net and income taxes	$ 1,217	$ 169	$ 1,048

Table of Contents

Gross Margin

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Energy	$ 517	$ 686	$ (169)
Contracted and capacity	340	196	144
Realized value of hedges	181	202	(21)
Total realized gross margin	1,038	1,084	(46)
Unrealized gross margin	676	(479)	1,155
Total gross margin	$ 1,714	$ 605	$ 1,109

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

a decrease of $169 million in energy, primarily as a result of a substantial increase in the price of coal, partially offset by an increase in power prices and a decrease in the cost of emissions allowances. The decrease in energy also includes a $13 million lower of cost or market fuel oil inventory adjustment recognized in the fourth quarter of 2008. In addition, generation volumes decreased 11% as a result of contracting dark spreads, lower demand that resulted in less generation from our intermediate and peaking facilities and second quarter 2008 planned outages to allow for the installation of emissions control equipment as part of our compliance with the Maryland Healthy Air Act;

a decrease of $21 million in realized value of hedges primarily as a result of a decrease in the settlement value of power hedges. In 2008, the average market prices for power exceeded the settlement value of power contracts. In 2007, the settlement value of power contracts exceeded market prices. The decrease in power hedges was partially offset by an increase in the amount by which market prices for coal exceeded the contract prices for the coal that we purchased under our long-term agreements; partially offset by

an increase of $144 million in contracted and capacity primarily related to higher capacity revenues for 2008 as a result of the commencement of the PJM RPM capacity market in June 2007.

The increase of $1.155 billion in unrealized gross margin was comprised of the following:

unrealized gains of $676 million in 2008, which include a $399 million net increase in the value of hedge contracts for future periods primarily related to changes in forward power and natural gas prices in 2008 and an increase of $277 million from power and fuel contracts that settled during the period for which net unrealized losses had been recorded in prior periods; and

unrealized losses of $479 million in 2007, which include $270 million from the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and a $209 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices in 2007.

Operating Expenses

The increase of $55 million in operating expenses is primarily a result of the following:

an increase of $52 million in operations and maintenance expense, which includes:

an increase of $29 million related to the timing of our planned outages and an increase in labor and chemical costs related to our pollution control equipment; and

$23 million in increased allocated corporate overhead costs. With the completion of several dispositions by Mirant in the second and third quarters of 2007 and the shutdown of units 3 and 4 of the Lovett generating facility in the second quarter of 2007, Mirant Mid-Atlantic received a

Table of Contents

greater allocation of Mirant s corporate overhead costs in the year ended December 31, 2008, than in the same period in 2007;

an increase of $11 million in depreciation and amortization expense related to pollution control equipment placed in service as part of our compliance with the Maryland Healthy Air Act; partially offset by

an increase of $8 million in gain on sales of assets, net primarily as a result of the sales of emissions allowances in 2008.

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 tables summarize the results of operations of our Northeast segment (in millions):

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Realized gross margin	$ 189	$ 280	$ (91)
Unrealized gross margin	(10)	(43)	33
Total gross margin	179	237	(58)
Operating Expenses:			
Operations and maintenance	167	179	(12)
Depreciation and amortization	19	25	(6)
Impairment losses		175	(175)
Gain on sales of assets, net	(30)	(49)	19
Total operating expenses	156	330	(174)
Operating income (loss)	23	(93)	116
Total other income, net	(1)	(7)	6
Income (loss) from continuing operations before reorganization items, net and income taxes	$ 24	$ (86)	$ 110

Gross Margin

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Energy	$ 73	$ 128	$ (55)
Contracted and capacity	90	87	3
Realized value of hedges	26	65	(39)
Total realized gross margin	189	280	(91)
Unrealized gross margin	(10)	(43)	33
Total gross margin	$ 179	$ 237	$ (58)

The decrease of $91 million in realized gross margin was principally a result of the following:

a decrease of $55 million in energy, primarily as a result of the shutdown of the Lovett facility, lower generation volumes and increased fuel costs, partially offset by higher power prices; and

a decrease of $39 million in realized value of hedges for our generation output, as a result of a decrease in the amount by which the settlement value of power contracts exceeded market prices and lower volumes hedged in 2008, partially offset by an increase in the settlement value of fuel contracts.

Table of Contents

The increase of $33 million in unrealized gross margin was comprised of unrealized losses of $10 million in 2008 compared to $43 million in 2007. The unrealized losses were related to the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and decreases in value associated with forward power and fuel contracts for future periods primarily as a result of increases in forward power prices.

Operating Expenses

The decrease of $174 million in operating expenses was principally the result of the following:

- a decrease of $175 million as a result of the impairment loss on our Lovett facility recognized in the second quarter of 2007. See Note 5 to our consolidated financial statements contained elsewhere in this report for additional information related to this impairment;

- a decrease of $12 million in operations and maintenance expense primarily related to the Lovett facility, which includes a decrease of $33 million in operating costs, partially offset by $17 million of shutdown costs at the Lovett facility incurred in 2008. See Note 5 to our consolidated financial statements contained elsewhere in this report for additional information related to the shutdown of the Lovett facility; and

- a decrease of $19 million in gain on sales of assets. In 2008, subsidiaries in our Northeast segment recognized a gain of $30 million, of which $24 million related to emissions allowances sold to third parties. In 2007, subsidiaries in our Northeast segment recognized a gain of $49 million which includes a $14 million gain on the sale of certain ancillary equipment included in the sale of the six U.S. natural gas-fired facilities and a $33 million gain on the sales of emissions allowances, of which $11 million related to emissions allowances sold to Mirant Mid-Atlantic that are eliminated in our consolidated statement of operations.

California

Our California segment consists of the Contra Costa, Pittsburg and Potrero facilities with total net generating capacity of 2,347 MW.

The following tables summarize the results of operations of our California segment (in millions):

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Realized gross margin	$ 127	$ 135	$ (8)
Unrealized gross margin			
Total gross margin	127	135	(8)
Operating Expenses:			
Operations and maintenance	76	74	2
Depreciation and amortization	23	13	10
Gain on sales of assets, net	(7)	(2)	(5)
Total operating expenses	92	85	7
Operating income	35	50	(15)
Total other expense (income), net	1	(5)	6
Income from continuing operations before reorganization items, net and income taxes	$ 34	$ 55	$ (21)

Gross Margin

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Energy	$ 4	$ 3	$ 1
Contracted and capacity	123	132	(9)
Total realized gross margin	127	135	(8)
Unrealized gross margin			
Total gross margin	$ 127	$ 135	$ (8)

The decrease of $9 million in contracted and capacity includes a $3 million lower of cost or market fuel oil inventory adjustment recognized in the fourth quarter of 2008 and extended outages at unit 3 of the Potrero generating facility in the first quarter of 2008.

Operating Expenses

The increase of $7 million in operating expenses was principally the result of higher development costs and higher depreciation expense in 2008, partially offset by lower maintenance expenses and an increase in gains on sales of assets, net primarily as a result of the sales of emissions allowances in 2008.

Other Operations

Other Operations includes proprietary trading and fuel oil management activities, unallocated corporate overhead, interest on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances. For the year ended December 31, 2007, Other Operations also included gains and losses related to the Back-to-Back Agreement, which was terminated pursuant to a settlement that became effective in the third quarter of 2007. See Pepco Litigation in Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Back-to-Back Agreement.

The following tables summarize the results of operations of our Other Operations segment (in millions):

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Realized gross margin	$ (17)	$ 126	$ (143)
Unrealized gross margin	120	(14)	134
Total gross margin	103	112	(9)
Operating Expenses:			
Operations and maintenance	28	94	(66)
Depreciation and amortization	10	10	
Gain on sales of assets, net	(2)	(5)	3
Total operating expenses	36	99	(63)
Operating income	67	13	54
Total other expense (income), net	123	(282)	405
Income (loss) from continuing operations before reorganization items, net and income taxes	$ (56)	$ 295	$ (351)

Table of Contents

Gross Margin

	Years Ended December 31, 2008	2007	Increase/ (Decrease)
Energy	$ (17)	$ 109	$ (126)
Contracted and capacity		17	(17)
Total realized gross margin	(17)	126	(143)
Unrealized gross margin	120	(14)	134
Total gross margin	$ 103	$ 112	$ (9)

The decrease of $143 million in realized gross margin was principally a result of the following:

- a decrease of $126 million in energy, comprised of a $83 million decrease from fuel oil management activities, a $37 million lower of cost or market fuel oil inventory adjustment recognized in the fourth quarter of 2008 and a $6 million decrease from proprietary trading activities. The significant decrease in the contribution from fuel oil management activities primarily relates to the timing of the settlement of contracts used to hedge the fair value of fuel oil inventory compared to the timing of the use or sale of the fuel oil; and

- a decrease of $17 million in contracted and capacity resulting from the termination of the Back-to-Back Agreement in the third quarter of 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for additional information related to the Pepco Settlement Agreement.

The increase of $134 million in unrealized gross margin was comprised of the following:

- unrealized gains of $120 million in 2008, which include a $65 million net increase in the value of contracts for future periods primarily related to changes in forward power prices in 2008 and an increase of $55 million from power and fuel contracts that settled during the period for which net unrealized losses had been recorded in prior periods; and

- unrealized losses of $14 million in 2007, including:

  - $102 million of unrealized losses related to proprietary trading and fuel oil management activities which include $115 million from the settlement of power and fuel contracts during the year for which unrealized gains had been recorded in prior periods and a $13 million net increase in value associated with contracts for future periods; partially offset by

  - $88 million of unrealized gains on the Back-to-Back Agreement and related hedges. The Back-to-Back Agreement was terminated in the third quarter of 2007.

Operating Expenses

The decrease of $63 million in operating expenses was primarily a result of a decrease of $66 million in operations and maintenance expense, which include:

a decrease of $32 million resulting from the 2007 increase in our estimated obligation to MC Asset Recovery under the Plan. See Note 16 to our consolidated financial statements contained elsewhere in this report for additional information related to MC Asset Recovery;

a decrease of $26 million related to corporate overhead costs included in Other Operations in 2007 but allocated across Mirant s operating segments in 2008;

a decrease of $16 million related to the 2007 bonus plan for dispositions;

a decrease of $9 million related to litigation contingencies; partially offset by

an increase of $27 million related to a decrease in curtailment gains on pension and postretirement benefits reflected as a reduction of operations and maintenance expense.

Table of Contents

Other Expense (Income), Net

Other expense (income), net decreased $405 million primarily as a result of the following:

- a decrease in other, net of $348 million, which includes a gain of $341 million in 2007 resulting from the termination of the Back-to-Back Agreement and a gain of $2 million for the refund of excess proceeds from the sales of shares distributed to Pepco, both as a result of the Pepco Settlement Agreement becoming fully effective. See Note 17 to our consolidated financial statements contained elsewhere in this report for additional information related to the Pepco Settlement Agreement;

- a decrease of $130 million in interest income primarily related to lower average cash balances and lower interest rates on invested cash; partially offset by

- a decrease of $73 million in interest expense related to lower debt outstanding and higher interest capitalized on construction projects in 2008.

Other Significant Consolidated Statements of Operations Comparison

Discontinued Operations

For the year ended December 31, 2008, income from discontinued operations was $50 million and included insurance recoveries related to the Sual generating facility outages that occurred prior to the sale.

For the year ended December 31, 2007, income from discontinued operations was $1.562 billion and included:

- a pre-tax gain of $2.003 billion on the sale of the Philippine business, a pre-tax gain of $63 million on the sale of the Caribbean business, a reduction to the previous impairment of six U.S. natural gas-fired facilities of $30 million and a gain of $8 million on the sale of Mirant NY-Gen; partially offset by

- an income tax provision of $704 million related to the sale of the Philippine business; and

- operating results for the discontinued operations.

See Note 11 to our consolidated financial statements contained elsewhere in this report for additional information related to the dispositions and discontinued operations.

2007 versus 2006

Gross Margin Overview

The following table details realized and unrealized gross margin by operating segment (in millions):

	Years Ended December 31,					
	2007			2006		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Mid-Atlantic	$ 1,084	$ (479)	$ 605	$ 834	$ 484	$ 1,318

Northeast	280	(43)	237	286	61	347
California	135		135	112	3	115
Other Operations	126	(14)	112	11	107	118
Eliminations	18		18	38		38
Total	$ 1,643	$ (536)	$ 1,107	$ 1,281	$ 655	$ 1,936

Table of Contents

Gross margin for the years ended December 31, 2007 and 2006, is further detailed as follows (in millions):

	Year Ended December 31, 2007					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 686	$ 128	$ 3	$ 109	$ 18	$ 944
Contracted and capacity	196	87	132	17		432
Realized value of hedges	202	65				267
Total realized gross margin	1,084	280	135	126	18	1,643
Unrealized gross margin	(479)	(43)		(14)		(536)
Total Gross Margin	$ 605	$ 237	$ 135	$ 112	$ 18	$ 1,107

	Year Ended December 31, 2006					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
Energy	$ 532	$ 117	$ 14	$ 71	$ 38	$ 772
Contracted and capacity	39	44	101	(60)		124
Realized value of hedges	263	125	(3)			385
Total realized gross margin	834	286	112	11	38	1,281
Unrealized gross margin	484	61	3	107		655
Total Gross Margin	$ 1,318	$ 347	$ 115	$ 118	$ 38	$ 1,936

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. For the years ended December 31, 2007 and 2006, contracted and capacity also included the Back-to-Back Agreement, which was terminated on August 10, 2007. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Pepco Settlement Agreement.

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 our coal supply contracts. 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 that are recorded as derivative contract assets and liabilities on our consolidated balance sheets, including the reversal of unrealized gains and losses recognized in prior periods and changes in value for future periods.

Our gross margin for the year ended December 31, 2007, was $1.107 billion as compared to $1.936 billion for the same period in 2006. The decrease in gross margin, which includes net unrealized gains and losses from our hedging activities, was principally a result of the following:

A decrease of $1.191 billion in unrealized gross margin was comprised of the following:

- unrealized losses of $536 million in 2007, which include $438 million from the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and a $98 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices in 2007; and unrealized gains of $655 million in 2006, which include a $433 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power prices in 2006 and $222 million from the settlement of power and fuel contracts during the period for which net unrealized losses had been recorded in prior periods.

Table of Contents

An increase of $362 million in realized gross margin primarily attributable to:

- an increase in contracted and capacity of $308 million, which includes the refund by Pepco of $36 million of payments made to it under the Back-to-Back Agreement for periods after May 31, 2006, as a result of the Settlement Agreement with Pepco becoming fully effective in August 2007;

- an increase in energy of $172 million as a result of an increase in power prices, a decrease in emissions prices, slightly higher generation volumes and the settlement of favorable fuel oil management positions; partially offset by

- a decrease of $118 million in incremental realized value of hedges.

Mid-Atlantic

Our Mid-Atlantic segment, which accounts for approximately half of our net generating capacity, includes four generating facilities with total net generating capacity of 5,230 MW.

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

	Years Ended December 31, 2007	2006	Increase/ (Decrease)
Realized gross margin	$ 1,084	$ 834	$ 250
Unrealized gross margin	(479)	484	(963)
Total gross margin	605	1,318	(713)
Operating Expenses:			
Operations and maintenance	360	333	27
Depreciation and amortization	81	74	7
Gain on sales of assets, net		(7)	7
Total operating expenses	441	400	41
Operating income	164	918	(754)
Total other expense (income), net	(5)	(4)	(1)
Income from continuing operations before reorganization items, net and income taxes	$ 169	$ 922	$ (753)

Gross Margin

	Years Ended December 31, 2007	2006	Increase/ (Decrease)
Energy	$ 686	$ 532	$ 154
Contracted and capacity	196	39	157
Realized value of hedges	202	263	(61)
Total realized gross margin	1,084	834	250

Unrealized gross margin	(479)	484	(963)
Total gross margin	$ 605	$ 1,318	$ (713)

The increase of $250 million in realized gross margin was principally a result of the following:

- an increase of $154 million in energy, primarily because of an increase in power prices, a decrease in emissions prices and slightly higher generation volumes;

- an increase of $157 million in contracted and capacity related to higher capacity revenues from the PJM RPM, which became effective in June 2007. See Item 1. Regulatory Environment for further discussion of RPM; and

54

Table of Contents

a decrease of $61 million in realized value of hedges of our generation output primarily as a result of a decrease in the amount by which the settlement value of power contracts exceeded market prices.

The decrease of $963 million in unrealized gross margin was comprised of the following:

unrealized losses of $479 million in 2007, which include $270 million from the settlement of power and fuel contracts during the period for which net unrealized gains had been recorded in prior periods and a $209 million net decrease in the value of hedge contracts for future periods primarily related to increases in forward power prices in 2007; and

unrealized gains of $484 million in 2006, which include a $312 million net increase in the value of hedge contracts for future periods primarily as a result of decreases in forward power prices in 2006 and $172 million from the settlement of power and fuel contracts during the year for which net unrealized losses had been recorded in prior periods, particularly during the high energy prices of late 2005.

Operating Expenses

Operating expenses increased $41 million primarily as a result of the following:

an increase of $27 million in operations and maintenance expense, of which $18 million was related to higher maintenance performed in conjunction with planned outages for the installation of pollution control equipment and $8 million related to increased corporate overhead allocations as a result of the dispositions in 2007;

an increase of $7 million in depreciation and amortization expense primarily related to equipment to improve environmental performance; and

a decrease of $7 million in gain on sales of assets, net primarily related to a gain of $6 million on the sale of a building in 2006.

Northeast

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

The following tables summarize the results of operations of our Northeast segment (in millions):

	Years Ended December 31,		Increase/
	2007	2006	(Decrease)
Realized gross margin	$ 280	$ 286	$ (6)
Unrealized gross margin	(43)	61	(104)
Total gross margin	237	347	(110)
Operating Expenses:			
Operations and maintenance	179	116	63
Depreciation and amortization	25	25	
Impairment losses	175	118	57
Gain on sales of assets, net	(49)	(46)	(3)
Total operating expenses	330	213	117

Operating income (loss)	(93)	134	(227)
Total other expense (income), net	(7)	9	(16)
Income (loss) from continuing operations before reorganization items, net and income taxes	$ (86)	$ 125	$ (211)

55

Table of Contents

Gross Margin

	Years Ended December 31, 2007	2006	Increase/ (Decrease)
Energy	$ 128	$ 117	$ 11
Contracted and capacity	87	44	43
Realized value of hedges	65	125	(60)
Total realized gross margin	280	286	(6)
Unrealized gross margin	(43)	61	(104)
Total gross margin	$ 237	$ 347	$ (110)

The decrease of $6 million in realized gross margin was principally a result of the following:

- a decrease of $60 million in realized value of hedges of our generation output, primarily as a result of a decrease in the amount by which the settlement value of power contracts exceeded market prices;
- an increase of $43 million in contracted and capacity from the implementation of the new FCM in the ISO-NE. See Item 1. Regulatory Environment for further information on the implementation of the new FCM; and
- an increase of $11 million in energy, primarily because of an increase in power prices and higher generation volumes.

The decrease of $104 million in unrealized gross margin was comprised of the following:

- unrealized losses of $43 million in 2007, which include $57 million from the settlement of power and fuel contracts during the period for which unrealized gains had been recorded in prior periods, partially offset by a $14 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power prices in 2007; and
- unrealized gains of $61 million in 2006, which include a $50 million net increase in the value of hedge contracts for future periods primarily related to decreases in forward power prices in 2006 and $11 million from the settlement of power and fuel contracts during the year for which unrealized losses had been recorded in prior periods, particularly during the high energy prices of late 2005.

Operating Expenses

Operating expenses increased $117 million primarily as a result of the following:

- an increase of $63 million in operations and maintenance which included:
  - an increase of $71 million in 2007, which represents that portion of the 2006 New York property tax settlement that reduced operating expenses for 2006, but which related to prior periods. See Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion; and

a decrease of $6 million related to a decrease in maintenance costs primarily as a result of the shutdown of Lovett units 3 and 4 in 2007 and repairs on Lovett unit 5 in 2006.

an increase of $57 million in impairment losses. In 2007, we recorded an impairment loss of $175 million on our Lovett facility. In 2006, we recorded an impairment loss of $118 million on the Bowline unit 3 suspended construction project. See Note 5 to our consolidated financial statements contained elsewhere in this report for additional information related to these impairments.

Table of Contents

California

Our California segment consists of the Contra Costa, Pittsburg and Potrero facilities with total net generating capacity of 2,347 MW.

The following tables summarize the results of operations of our California segment (in millions):

	Years Ended December 31, 2007	2006	Increase/ (Decrease)
Realized gross margin	$ 135	$ 112	$ 23
Unrealized gross margin		3	(3)
Total gross margin	135	115	20
Operating Expenses:			
Operations and maintenance	74	63	11
Depreciation and amortization	13	13	
Gain on sales of assets, net	(2)		(2)
Total operating expenses	85	76	9
Operating income	50	39	11
Total other expense (income), net	(5)	(34)	29
Income from continuing operations before reorganization items, net and income taxes	$ 55	$ 73	$ (18)

Gross Margin

	Years Ended December 31, 2007	2006	Increase/ (Decrease)
Energy	$ 3	$ 14	$ (11)
Contracted and capacity	132	101	31
Realized value of hedges		(3)	3
Total realized gross margin	135	112	23
Unrealized gross margin		3	(3)
Total gross margin	$ 135	$ 115	$ 20

The increase in our contracted and capacity gross margin and decrease in our energy gross margin were primarily a result of the commencement of a new tolling agreement in the first quarter of 2007 at our Contra Costa and Pittsburg facilities. See Item 1. Business Segments for additional information regarding the tolling agreement.

Operating Expenses

The increase of $9 million in operating expenses includes an increase of $11 million in operations and maintenance expense in 2007, resulting from higher maintenance costs related to outages and a $5 million property tax settlement in 2006.

Other Expense (Income), Net

The decrease of $29 million in other expense (income), net is primarily a result of a gain of $26 million in 2006 related to the transfer of Contra Costa unit 8 to PG&E. See California Settlement in Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion.

Table of Contents

Other Operations

Other Operations includes proprietary trading, fuel oil management and gains and losses related to the Back-to-Back Agreement, which was terminated pursuant to a settlement that became effective in the third quarter of 2007. See Pepco Litigation in Note 17 to our consolidated financial statements contained elsewhere in this report for further discussion of the Back-to-Back Agreement. Other Operations also includes unallocated corporate overhead, interest on debt at Mirant Americas Generation and Mirant North America and interest income on our invested cash balances.

The following tables summarize the results of operations of our Other Operations segment (in millions):

	Years Ended December 31, 2007	2006	Increase/ (Decrease)
Realized gross margin	$ 126	$ 11	$ 115
Unrealized gross margin	(14)	107	(121)
Total gross margin	112	118	(6)
Operating Expenses:			
Operations and maintenance	94	80	14
Depreciation and amortization	10	25	(15)
Impairment losses		1	(1)
Gain on sales of assets, net	(5)	(40)	35
Total operating expenses	99	66	33
Operating income	13	52	(39)
Total other expense (income), net	(282)	128	(410)
Income (loss) from continuing operations before reorganization items, net and income taxes	$ 295	$ (76)	$ 371

Gross Margin

	Years Ended December 31, 2007	2006	Increase/ (Decrease)
Energy	$ 109	$ 71	$ 38
Contracted and capacity	17	(60)	77
Total realized gross margin	126	11	115
Unrealized gross margin	(14)	107	(121)
Total gross margin	$ 112	$ 118	$ (6)

The increase of $115 million in realized gross margin was principally a result of the following:

an increase of $77 million in contracted and capacity related to a decrease in realized losses on the Back-to-Back Agreement and the related hedges of this contract and, as a result of the Settlement Agreement with Pepco becoming fully effective in August 2007, the refund by Pepco of $36 million of payments made to it under the Back-to-Back Agreement for periods after May 31, 2006; and

- an increase of $38 million in energy related to our proprietary trading and fuel oil management activities as favorable positions entered into prior to 2007 were settled in the current period.

The decrease of $121 million in unrealized gross margin was comprised of the following:

- unrealized losses in 2007 of $14 million, including:
  - unrealized losses on proprietary trading and fuel oil management activities of $102 million, which include $115 million from the settlement of power and fuel contracts during the period for which

Table of Contents

unrealized gains had been recorded in prior periods and a $13 million net increase in value associated with contracts for future periods; partially offset by

unrealized gains on the Back-to-Back Agreement and related hedges of $88 million primarily as a result of an increase in forward value related to the prices for forward capacity in PJM and the resulting decrease in the fair value of the liability of that agreement.

unrealized gains in 2006 of $107 million, which include unrealized gains on proprietary trading and fuel oil management activities of $61 million and unrealized gains on the Back-to-Back Agreement of $46 million.

Operating Expenses

Operating expenses increased $33 million primarily as a result of the following:

a decrease of $35 million in gain on sales of assets, net primarily as a result of the 2006 gain on the sale of our remaining claims in the Enron bankruptcy;

an increase of $14 million in operations and maintenance expense primarily as a result of the following:

an increase of $35 million related to the accrual for costs of MC Asset Recovery that we are required to pay under the terms of the Plan. See Note 16 to our consolidated financial statements contained elsewhere in this report for further discussion;

an increase of $27 million related to an increase in incentive compensation, including a bonus plan established in connection with the disposition in 2007 of certain businesses and assets;

an increase of $9 million in litigation contingency accruals; partially offset by

a decrease related to a curtailment gain of $32 million resulting from an amendment to our postretirement benefits plan;

a decrease of $19 million in bankruptcy related charges and prepetition disputes; and

a decrease of $15 million in depreciation expense as a result of the complete depreciation of certain computer equipment.

Other Expense (Income), Net

Other expense (income), net decreased $410 million primarily as a result of the following:

a gain of $341 million resulting from the termination of the Back-to-Back Agreement;

an increase of $126 million in interest income related to increased cash balances as a result of the proceeds from dispositions completed in 2007; partially offset by

a decrease in gain on sales of investments, which included a gain of $54 million in 2006 from the sale of a portion of our investment in InterContinental Exchange and $19 million on the sale of our two NYMEX seats and shares.

Other Significant Consolidated Statements of Operations Comparison

Provision (Benefit) for Income Taxes

The provision for income taxes increased by $559 million for the year ended December 31, 2007, compared to 2006, primarily as a result of the $552 million benefit in 2006 related to the release of the valuation allowance

Table of Contents

pertaining to deferred tax assets previously recorded. The 2006 benefit included the estimated value of the NOLs that were used to offset the 2007 taxable gain resulting from the sale of the Philippine business.

Discontinued Operations

For the year ended December 31, 2007, we reported net income from discontinued operations of $1.562 billion, which includes the reclassification of the results of operations related to the dispositions. Income from discontinued operations increased $1.450 billion for the year ended December 31, 2007, as compared to 2006 primarily as a result of the following:

- an increase of $2.479 billion in gain on sales of assets, which included:
  - an increase of $2.003 billion as a result of the sale of the Philippine business in 2007;
  - an increase of $63 million as a result of the gain on the sale of the Caribbean business in 2007;
  - an increase of $405 million as a result of the impairments recorded on six U.S. natural gas-fired facilities. For the year ended December 31, 2006, we recorded total impairments of $375 million. For the year ended December 31, 2007, we recorded a reduction to the impairment of $30 million; and
  - an increase of $8 million as a result of the sale of NY-Gen in 2007.
- a 2007 gain of $24 million related to the agreement for Wrightsville transmission credits. See Note 11 to our consolidated financial statements contained elsewhere in this report for additional information on the Wrightsville transmission credits;
- an increase in the provision for income taxes of $793 million, primarily related to the sale of the Philippine business; and
- a decrease of $260 million in income from discontinued operations because of the completion of the dispositions, which occurred in the second and third quarters of 2007.

See Note 11 to our consolidated financial statements contained elsewhere in this report for additional information related to discontinued operations.

Reorganization Items, net

Reorganization items, net for the years ended December 31, 2007 and 2006, are comprised of the following (in millions):

	Years Ended December 31,		
	2007	2006	Increase/ (Decrease)
Gain on the New York property tax settlement	$	$ (163)	$ 163
Professional fees and administrative expense	3	2	1
Interest income, net	(5)	(3)	(2)

Total	$ (2)	$ (164)	$ 162

Under the terms of the New York property tax settlement, in February 2007 we received refunds totaling approximately $163 million for 1995 through 2003 and paid unpaid but accrued taxes of approximately $115 million for 2003 through 2006. See Note 17 to our consolidated financial statements contained elsewhere in this report for additional information.

Table of Contents

Liquidity and Capital Resources

Sources of Funds and Capital Structure

The principal sources of liquidity for our future operations and capital expenditures are expected to be: (1) existing cash on hand and 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; and (3) letters of credit issued under Mirant North America s senior secured term loan.

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

	At December 31, 2008	At December 31, 2007
Cash and Cash Equivalents:		
Mirant Corporation	$ 1,469	$ 4,232
Mirant Americas Generation		1
Mirant North America	229	455
Mirant Mid-Atlantic	125	242
Other	8	31
Total cash and cash equivalents	1,831	4,961
Less: Cash restricted and reserved for other purposes	2	15
Total available cash and cash equivalents	1,829	4,946
Available under credit facilities	583	710
Total cash, cash equivalents and credit facilities availability	$ 2,412	$ 5,656

We consider all short-term investments with an original maturity of three months or less to be cash equivalents. At December 31, 2008, except for amounts held in bank accounts to cover upcoming payables, all of our cash and cash equivalents were invested in AAA-rated U.S. Treasury money market funds.

Available under credit facilities at December 31, 2008, reflects a $45 million reduction as a result of the expectation that Lehman Commercial Paper, Inc., which filed for bankruptcy in October 2008, will not honor its $45 million commitment under the Mirant North America senior secured revolving credit facility. See Item 1A. Risk Factors for a description of risks related to the lenders under our credit facility.

Table of Contents

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.

A significant portion of cash from our operations is generated by the power generation 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 Mirant North America. Mirant Mid-Atlantic s ability to satisfy the criteria set by that covenant in the future could be impaired by factors which negatively affect its financial performance, including interruptions in operation or curtailment of operations to comply with environmental restrictions, significant capital and other expenditures and adverse conditions in the power and fuel markets.

Mirant North America is an intermediate holding company that is a subsidiary of Mirant Americas Generation and the parent of its indirect subsidiaries, including Mirant Mid-Atlantic. Mirant North America incurred certain indebtedness pursuant to its senior notes and senior secured credit facilities secured by the assets of Mirant North America and its subsidiaries (other than Mirant Mid-Atlantic and Mirant Energy Trading). The indebtedness of Mirant North America includes certain covenants typical in such notes and credit facilities, including restrictions on dividends, distributions and other restricted payments. Further, the 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 transaction 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.

The ability of Mirant Americas Generation to pay its obligations is dependent on the receipt of dividends from Mirant North America, capital contributions from Mirant Corporation and its ability to refinance all or a portion of those obligations as they become due.

Table of Contents

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

- expected expenditures with respect to maintenance activities and capital improvements, and related outages;
- expected collateral posted in support of our business;
- effects of market price volatility on the amount of collateral posted for economic hedge transactions and risk management transactions;
- effects of market price volatility on fuel pre-payment requirements;
- seasonal and intra-month working capital requirements;
- the development of new generating facilities; and
- debt service obligations.

Our operating cash flows may be affected by, among other things: (1) demand for electricity; (2) the difference between the cost of fuel used to generate electricity and the market value of the electricity generated; (3) commodity prices (including prices for electricity, emissions allowances, natural gas, coal and oil); (4) the cost of ordinary course operations and maintenance expenses; (5) planned and unplanned outages; (6) terms with trade creditors; and (7) cash requirements for capital expenditures relating to certain facilities (including those necessary to comply with environmental regulations).

As noted above, 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 December 31, 2008, 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 $354 million at Mirant North America and its subsidiaries. Of this amount, $125 million was held by Mirant Mid-Atlantic which, as of December 31, 2008, met the tests under the leveraged lease documentation permitting it to make distributions to Mirant North America. While Mirant North America is in compliance with its financial covenants, as of December 31, 2008, it is restricted from making distributions because of the free cash flow requirements under the restricted payment test of its senior credit facility. The primary factor lowering the free cash flow calculation in the restricted payment test 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. Except for permitted distributions to cover interest payable on Mirant Americas Generation s senior notes, the $3.883 billion of net assets of Mirant North America and its subsidiaries were restricted from distribution from Mirant North America to its parent, Mirant Americas Generation, as of December 31, 2008. Notwithstanding such restriction, we think that we have sufficient liquidity for our future operations, capital expenditures and debt service obligations from existing cash on hand (including $1.469 billion at Mirant Corporation), expected cash flows from the operations of our subsidiaries and ability to issue letters of credit or make borrowings under the Mirant North America senior credit facilities.

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; (4) the development of new generating facilities; and (5) return of cash to stockholders.

Return of Cash to Stockholders. Since November 2007, we have returned $4.056 billion of excess cash to our stockholders through repurchases of our common stock, including $2.74 billion in 2008. See *Overview* in this Item 7 for further discussion of our share repurchases.

Capital Expenditures. Capital expenditures excluding capitalized interest were $683 million, $560 million and $133 million for the years ended December 31, 2008, 2007 and 2006, respectively. Our capital expenditures, excluding capitalized interest, for 2009 and 2010 are expected to be approximately $754 million and $422 million, respectively. This forecast does not assume any construction of new generating units during the forecast period. Instead, the current capital expenditure program, which is expected to be funded by cash on hand and operating cash flow, focuses on efficiency, safety, reliability and compliance with existing environmental laws and obligations under consent decrees to which we are a party, including capital expenditures made to comply with the limitations for SO2, NOx and mercury emissions under the Maryland Healthy Air Act. For a more detailed discussion of environmental expenditures we expect to incur in the future, see Item 1. Business .

Debt Service. At December 31, 2008, we had $2.676 billion of long-term debt with expected interest payments of approximately $199 million for 2009. See Note 6 to our consolidated financial statements contained elsewhere in this report for additional information

Under the terms of its senior secured term facility, Mirant North America is required to use 50% of its free cash flow for each fiscal year (less amounts paid to Mirant Americas Generation for the purpose of paying interest on the Mirant Americas Generation senior notes) to pay down its senior secured term loan, in addition to its scheduled amortization of $5 million per year. The percentage of free cash flow that Mirant North America is required to use to pay down its senior secured term loan may be reduced to 25% upon the achievement of a net debt to EBITDA ratio of less than 2:1. At December 31, 2008, Mirant North America s net debt to EBITDA ratio was less than 2:1. As such, it was required to use 25% of its free cash flow to pay down its senior secured term loan. We estimate this prepayment, which will be made during the first quarter of 2009, to be $37 million.

Mirant Mid-Atlantic Operating Leases. Mirant Mid-Atlantic leases the Dickerson and Morgantown baseload units and associated property through 2029 and 2034, respectively. Mirant Mid-Atlantic has an option to extend the leases. Any extensions of the respective leases would be for less than 75% of the economic useful life of the facility, as measured from the beginning of the original lease term through the end of the proposed remaining lease term. We are accounting for these leases as operating leases. While there is variability in the scheduled payment amounts over the lease term, we recognize rent expense for these leases on a straight-line basis in accordance with the applicable accounting literature. Rent expense under the Mirant Mid-Atlantic leases was $96 million for the years ended December 31, 2008, 2007 and 2006. As of December 31, 2008, the total notional minimum lease payments for the remaining term of the leases aggregated approximately $2 billion and the aggregate termination value for the leases was approximately $1.4 billion and generally decreases over time. In addition, Mirant Mid-Atlantic is required to post rent reserves in an aggregate amount equal to the greater of the next six months rent, 50% of the next 12 months rent or $75 million.

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 trade 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. Trade credit support includes cash collateral, letters of credit 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 December 31, 2008, we had approximately $111 million of posted cash collateral and $301 million of letters of credit outstanding primarily to support our asset management activities, debt service and rent reserve requirements and other commercial arrangements. Our liquidity requirements are highly dependent on the level of our hedging activities, forward prices for energy, emissions allowances and fuel, commodity market volatility and credit terms with third parties. See Note 10 to our consolidated financial statements contained elsewhere in this report for additional information.

Table of Contents

The following table summarizes at December 31, 2008 and 2007, for our continuing operations, cash collateral posted with counterparties and brokers, letters of credit issued and surety bonds (in millions):

	At December 31, 2008	At December 31, 2007
Cash collateral posted energy trading and marketing	$ 67	$ 96
Cash collateral posted other operating activities	44	14
Letters of credit energy trading and marketing	76	100
Letters of credit debt service and rent reserves	101	78
Letters of credit other operating activities	124	112
Surety bonds energy trading and marketing	25	
Total	$ 437	$ 400

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

Our debt obligations, off-balance sheet arrangements and contractual obligations as of December 31, 2008, are as follows (in millions):

	Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations by Year						
	Total	2009	2010	2011	2012	2013	>5 Years
Long-term debt	$ 4,471	$ 245	$ 210	$ 717	$ 162	$ 1,351	$ 1,786
Mirant Mid-Atlantic operating leases	2,013	142	140	134	132	138	1,327
Other operating leases	57	9	9	7	5	6	21
Fuel commitments	1,254	374	335	314	196	35	
Maryland Healthy Air Act	677	490	187				
Other	336	186	41	32	22	15	40
Total payments	$ 8,808	$ 1,446	$ 922	$ 1,204	$ 517	$ 1,545	$ 3,174

Our contractual obligations table does not include our derivative obligations which are discussed in Note 4 to our consolidated financial statements contained elsewhere in this report and our asset retirement obligations which are discussed in Note 9 to our consolidated financial statements contained elsewhere in this report.

Long-term debt includes the current portion of long-term debt and long-term debt on our consolidated balance sheets. Long-term debt also includes estimated interest on debt. Interest on our variable interest debt is based on the U.S. Dollar LIBOR curve as of December 31, 2008.

Operating leases are off-balance sheet arrangements. These amounts primarily relate to our minimum lease payments associated with our lease of the Dickerson and Morgantown baseload units at our Mid-Atlantic facilities.

Fuel commitments primarily relate to long-term coal agreements and related transportation agreements.

Maryland Healthy Air Act commitments reflect the remaining capital expenditures that we expect to incur to comply with the limitations for SO2, NOx and mercury emissions under the Maryland Healthy Air Act.

Other represents open purchase orders less invoices received related to open purchase orders for general procurement of products and services purchased in the ordinary course of business. These include construction, maintenance and labor activities at our generating facilities. Other also includes our LTSA associated with the maintenance of turbines at our Kendall facility, limestone supply and transportation agreements, our estimated pension and other postretirement benefit funding obligations, deferred compensation plans, FIN 48 liabilities and miscellaneous long-term liabilities, which are included in other noncurrent liabilities on the consolidated balance sheet.

Cash Flows

The changes in our cash flows are detailed as follows (in millions):

	Years Ended December 31,					
	2008	2007	Increase/ (Decrease)	2007	2006	Increase/ (Decrease)
Cash and cash equivalents, beginning of period	$ 4,961	$ 1,385	$ 3,576	$ 1,385	$ 1,551	$ (166)
Net cash provided by operating activities:						
Continuing operations	677	786	(109)	786	137	649
Discontinued operations	50	178	(128)	178	432	(254)
Net cash provided by (used in) investing activities:						
Continuing operations	(719)	(524)	(195)	(524)	5	(529)
Discontinued operations	25	5,281	(5,256)	5,281	(163)	5,444
Net cash provided by (used in) financing activities:						
Continuing operations	(3,163)	(1,477)	(1,686)	(1,477)	(758)	(719)
Discontinued operations		(669)	669	(669)	181	(850)
Effect of exchange rate changes		1	(1)	1		1
Cash and cash equivalents, end of period	$ 1,831	$ 4,961	$ (3,130)	$ 4,961	$ 1,385	$ 3,576

2008 versus 2007

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 $109 million for the year ended December 31, 2008, compared to the same period in 2007, primarily as a result of the following:

a decrease in realized gross margin of $242 million in 2008, compared to the same period in 2007, excluding the non-cash change in lower of cost or market inventory adjustments of $58 million, of which $54 million was recognized in the fourth quarter of 2008. See *Results of Operations* for additional discussion of our performance in 2008 compared to the same period in 2007;

an increase in cash used of $80 million related to changes in net accounts receivable, accounts payable and accrued liabilities and other changes in working capital in 2008 compared to 2007, primarily as a result of increases in power prices in 2008 and the net refund of $48 million related to a New York property tax settlement in 2007. The increase in cash used is net of $47 million of cash provided by a net increase in collateral that we received from counterparties in 2008;

a decrease in cash provided of $70 million related to the Pepco Settlement Agreement becoming fully effective in 2007, which is included in other assets in our consolidated statements of cash flows. Pepco repaid $70 million in 2007 for an advance payment made in 2006 under the Pepco Settlement Agreement;

a decrease in cash provided of $74 million for interest, net, reflecting lower interest income as a result of lower interest rates on invested cash as well as lower cash balances as a result of share repurchases partially offset by lower interest expense from lower outstanding debt and higher capitalized interest; and an increase in cash used of $23 million related to additional contributions to our pension plans in 2008 as compared to 2007.

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

- a decrease in cash used of $173 million because of changes in funds on deposit. In 2008, we had net cash collateral returned to us of $104 million, primarily related to the cash collateral account to support issuance of letters of credit under the Mirant North America senior secured term loan. In 2007, we posted an additional $70 million of cash collateral;
- a decrease in cash used of $124 million for inventories primarily as a result of the reduction of fuel inventory levels;
- a decrease in operations and maintenance expense of $46 million excluding a non-cash decrease in curtailment gains on pension and postretirement benefits of $27 million and other non-cash items; and
- a decrease in cash used of $37 million for settlement of bankruptcy related claims and expenses.

Investing Activities. Net cash used in investing activities from continuing operations increased by $195 million for the year ended December 31, 2008, compared to the same period in 2007. This difference was primarily a result of the following:

- an increase in cash used of $143 million for capital expenditures (including capitalized interest of $20 million) for projects under construction primarily related to our environmental capital expenditures for our Maryland generating facilities;
- an increase in cash used of $37 million primarily related to $34 million placed in an escrow account in September 2008 to satisfy the conditions of Mirant Potomac River s settlement agreement with the City of Alexandria; and
- a decrease of $15 million in proceeds from the sales of assets in 2008 as compared to 2007. In 2008, we received $42 million of proceeds from the sale of assets, primarily from the sale of emissions allowances. In 2007, we received $57 million of proceeds from the sale of assets, which included approximately $30 million from the sale of ancillary equipment included in the sale of the six U.S. natural gas-fired facilities.

Financing Activities. Net cash used in financing activities from continuing operations increased by $1.686 billion for the year ended December 31, 2008, compared to the same period in 2007. This difference was primarily a result of the following:

- an increase in cash used of $1.453 billion for share repurchases. See Note 13 to our consolidated financial statements contained elsewhere in this report for additional information on share repurchases;
- an increase in cash used of $240 million for repayments and purchases of long-term debt primarily as a result of the retirement of Mirant Americas Generation senior notes due in 2011 of $276 million in 2008 and $39 million in 2007; partially offset by
- an increase of $7 million in proceeds from the exercise of stock options in 2008 as compared to 2007.

Discontinued Operations

Operating Activities. In 2008, net cash provided by operating activities from discontinued operations was primarily a result of $41 million of business interruption insurance recoveries related to the outages of the Sual generating facility and $7 million from the sale of transmission credits from our previously owned Wrightsville facility. In 2007, net cash provided by operating activities from discontinued operations included cash flows from the Philippine and Caribbean businesses, six U.S. natural gas-fired facilities and Mirant NY-Gen.

Table of Contents

Investing Activities. Net cash provided by investing activities from discontinued operations was $25 million for the year ended December 31, 2008, compared to $5.281 billion for the same period in 2007. This difference was primarily a result of the following:

- 2007 results included the $5.410 billion in proceeds from the sale of our Caribbean business in the third quarter of 2007 and our Philippine business and six U.S. natural gas-fired facilities in the second quarter of 2007, partially offset by
- a decrease in cash used of $65 million that related to the cash and cash equivalents balance that was included in the assets sold as part of the Philippine business in 2007;
- a decrease in cash used of $47 million that related to the cash and cash equivalents balance that was included in the assets sold as part of the Caribbean business in 2007;
- a decrease in cash used of $20 million primarily related to capital expenditures incurred in 2007 at our Caribbean business prior to its disposition; and
- 2008 results included $25 million in insurance recoveries related to repairs to the Sual generating facility and the Swinging Bridge facility of Mirant NY-Gen.

Financing Activities. In 2007, net cash used in financing activities was $669 million and primarily related to the repayment of $700 million of long-term debt of our Philippine business, $83 million related to West Georgia and $14 million related to our Caribbean business. These payments were partially offset by a decrease in debt service reserves of $125 million.

2007 versus 2006

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 increased $649 million for the year ended December 31, 2007, compared to 2006, primarily as a result of the following:

- an increase in realized gross margin of $289 million for the year ended December 31, 2007, compared to 2006, excluding the non-cash change in lower of cost or market inventory adjustments of $73 million. See *Results of Operations* for additional discussion of our performance in 2007 compared to 2006;
- an increase of $761 million resulting from a reduction in bankruptcy related claims and expenses. In 2007, we paid $17 million in claims payable for the New York entities, $32 million related to MC Asset Recovery and $4 million related to other Mirant claims. In 2006, we paid $1.804 billion of bankruptcy claims, of which $814 million was reflected in cash from operations;
- an increase of $140 million related to the Settlement Agreement with Pepco becoming fully effective in the third quarter of 2007. Pepco repaid $70 million in 2007 for an advance payment made in the third quarter of 2006 under the Settlement Agreement. These amounts are included in other assets in the consolidated statements of cash flows;

an increase of $155 million related to increases in net interest income as a result of higher cash balances resulting from the dispositions completed in 2007;

an increase from the receipt in 2007 of a net refund of $48 million related to the New York property tax settlement, which is included in receivables, net in the consolidated statements of cash flows; and

an increase of $12 million primarily related to changes in our fuel oil and emissions inventories. In 2007, fuel inventory increased $88 million and emissions inventory decreased $15 million. In 2006, fuel inventory increased $38 million and emissions inventory increased $50 million.

The increases in operating activities were partially offset by the following:

- a decrease of $516 million as a result of changes in posted collateral levels, which are included in funds on deposit in the consolidated statements of cash flows. For the year ended December 31, 2007, we posted an additional $70 million of cash collateral primarily to support energy marketing activities. The change in collateral for the year ended December 31, 2006, provided a source of cash of $446 million primarily because of a decrease in cash collateral to support energy marketing activities of $592 million, and a reduction of $56 million in cash collateral posted in connection with the Mirant Mid-Atlantic lease upon posting $75 million of letters of credit. These amounts were partially offset by a use of cash as a result of the deposit of $200 million into a cash collateral account to support the issuance of letters of credit;

- a decrease of $77 million resulting from an increase in operations and maintenance expenses. See results of operations for additional discussion;

- a decrease of $60 million primarily as a result of the return in 2007 of deposits previously posted by our counterparties which is included in accounts payable and accrued liabilities in the consolidated statements of cash flows;

- a decrease of $65 million relating to changes in net accounts receivable and accounts payable in 2007 compared to 2006; and

- a decrease of $38 million related to all other changes in operating assets and liabilities.

Investing Activities. Net cash used in investing activities from continuing operations increased by $529 million for the year ended December 31, 2007, compared to 2006. This difference was primarily a result of the following:

- an increase of $449 million in capital expenditures (including capitalized interest of $22 million) primarily because of our environmental capital expenditures for our Mid-Atlantic generating facilities; and

- a decrease in proceeds from the sales of assets and investments of $86 million. In 2007, we received proceeds from the sale of assets of $57 million, which included approximately $30 million from the sale of ancillary equipment included in the sale of the six U.S. natural gas-fired facilities and $22 million from the sale of equipment from the Bowline unit 3 suspended construction project. In 2006, we received $143 million from the sale of assets, which included $45 million from the sale of our remaining bankruptcy claims against Enron and its subsidiaries and $58 million from the sale of a portion of our investment in InterContinental Exchange.

Financing Activities. Net cash used in financing activities from continuing operations increased by $719 million for the year ended December 31, 2007, compared to 2006. This difference was primarily a result of the following:

- a decrease in proceeds from the issuance of long-term debt of $2.017 billion. Proceeds from the issuance of long-term debt in 2006 included $850 million from the Mirant North America senior notes offering, $700 million from the Mirant North America senior secured term loan and $465 million drawn on the Mirant North America senior secured revolving credit facility;

- a decrease in the repayments of long-term debt of $1.285 billion, which includes $990 million of principal payments for debt settled under the Plan in 2006. In 2007, we paid $138 million on the Mirant North America senior secured term loan and repurchased $39 million of the Mirant Americas Generation 8.3% senior notes due in 2011. In 2006, we repaid $465 million on the Mirant North America senior secured revolving credit facility and $990 million of principal payments for debt settled under the Plan in 2006;

a decrease in debt issuance costs of $51 million. In 2006, we paid $51 million in debt issuance costs associated with Mirant North America s debt offering, senior secured term loan and secured revolving credit facility; and

- an increase of $47 million used for stock repurchases. In 2007, stock repurchases included 26.66 million shares of Mirant common stock for $1 billion under the accelerated share repurchase program, 8.27 million shares of Mirant common stock under the open market share repurchase program for approximately $316 million, of which $17 million had not yet been paid as of December 31, 2007, and approximately 245,000 shares of Mirant common stock in odd lot buybacks for approximately $9 million. In 2006, we repurchased 43 million shares of our common stock for $1.228 billion pursuant to a tender offer in 2006 and 1.18 million shares for approximately $32 million under the share repurchase program.

Discontinued Operations

Operating Activities. Net cash provided by operating activities from discontinued operations decreased by $254 million for the year ended December 31, 2007, compared to 2006. In 2006, operating activities included cash flows from the Philippine and Caribbean businesses and six U.S. natural gas-fired facilities for the entire year. In 2007, operating activities included all the discontinued businesses and facilities through their respective dates of sale.

Investing Activities. Net cash provided by investing activities from discontinued operations increased by $5.444 billion for the year ended December 31, 2007, compared to 2006. This difference was primarily a result of the following:

- an increase of $5.410 billion in proceeds from the sale of assets and investments, primarily from the sale of our Philippine and Caribbean businesses and six U.S. natural gas-fired facilities in the second and third quarters of 2007;
- a decrease of $65 million in cash that was included in the assets sold as part of the Philippine business;
- a decrease of $47 million in cash that was included in the assets sold as part of the Caribbean business;
- an increase related to the purchases in 2006 of the remaining 5.15% ownership in Mirant Sual for $35 million and the remaining 4.26% interest in Mirant Pagbilao for $40 million; and
- an increase as a result of funding in 2006 of $24 million in accordance with the terms and conditions of a stockholder loan agreement for the construction and installation of new generating units at Point Lisas, Trinidad.

Financing Activities. Net cash used in financing activities from discontinued operations increased by $850 million for the year ended December 31, 2007, compared to 2006. This difference was primarily a result of the following:

- a decrease of $78 million in repayments of long-term debt. In 2007, we repaid $700 million related to our Philippine business, $83 million related to West Georgia and $14 million related to our Caribbean business. In 2006, we repaid $551 million related to our Philippine business, $268 million related to our Caribbean business, $56 million related to West Georgia and $2 million related to Zeeland;
- a decrease of $981 million in proceeds from the issuance of long-term debt primarily from the issuance of $700 million by Mirant Asia-Pacific, $100 million by Mirant Trinidad Investments and $180 million by Mirant JPSCO Finance Ltd. in 2006;
- a decrease in debt issuance costs of $40 million primarily related to the Philippines; and
- a decrease in the release of cash deposited in debt service reserves of $10 million.

70

Table of Contents

Critical Accounting Estimates

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

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

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

Revenue Recognition and Accounting for Energy Trading and Marketing Activities

Nature of Estimates Required. We utilize two comprehensive accounting models, an accrual model and a fair value model, in reporting our consolidated financial position and results of operations. 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 earned and collection is probable as a result of electricity delivered 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 hedge economically our electricity generating facilities 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.

Pursuant to SFAS 133, derivative financial instruments are reflected in our financial statements at fair value, with changes in fair value recognized currently in earnings unless they qualify for a scope exception. 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 consolidated balance sheets. Transactions that are not accounted for using the fair value model under SFAS 133 are either not derivatives or qualify for a scope exception and are accounted for under accrual accounting. With the adoption of SFAS 157 on January 1, 2008, we no longer defer unobservable inception gains and losses, which are transacted at different prices between the bid price and the 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. Our view is 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. If no active market exists, we estimate the fair value of certain derivative financial instruments using price extrapolation, interpolation and other quantitative methods. 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 4 to our 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 1% of our total assets and less than 1% of our total liabilities measured at fair value at December 31, 2008.

The fair value of derivative contract assets and liabilities in our consolidated balance sheets is also affected by our assumptions as to time value, credit risk and nonperformance 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. The credit risk reflected in the fair value of our derivative contract assets and the nonperformance 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 under SFAS 133, 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 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. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk for further sensitivities in our assumptions used to calculate fair value. See Note 4 to our consolidated financial statements contained elsewhere in this report for further information on derivative financial instruments related to energy trading and marketing activities.

Long-Lived Assets

Estimated Useful Lives

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

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

Table of Contents

composite depreciation for groups of similar assets and establish an average useful life for each group of related assets. In accordance with SFAS 144, we cease depreciation on long-lived assets classified as held for sale. Also, we may revise the remaining useful life of an asset held and used subject to impairment testing. See Note 5 to our consolidated financial statements contained elsewhere in this report for additional information related to our property, plant and equipment.

Effect if Different Assumptions Used. The determination of estimated useful lives is dependent on subjective factors such as expected market conditions, commodity prices and anticipated capital expenditures. Since composite depreciation rates are used, the actual useful life of a particular asset may differ materially from the useful life estimated for the related group of assets. A 10% increase in the weighted average useful lives of our facilities would result in a $15 million decrease in annual depreciation expense. A 10% decrease in the weighted average useful lives of our facilities would result in a $14 million increase in annual depreciation expense. In the event the useful lives of significant assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities recognized for future asset retirement obligations may be insufficient and impairments in the carrying value of tangible and intangible assets may result.

Asset Retirement Obligations

Nature of Estimates Required. We account for asset retirement obligations under SFAS 143 and FIN 47. SFAS 143 and FIN 47 require an entity to recognize the fair value of a liability for conditional and unconditional asset retirement obligations in the period in which they are incurred. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 and FIN 47 are those obligations for which a requirement exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Asset retirement obligations are estimated using the estimated current cost to satisfy the retirement obligation, increased for inflation through the expected period of retirement and discounted back to present value at our credit-adjusted risk free rate. We have identified certain asset retirement obligations within our power generating operations and have a noncurrent liability of $40 million recorded as of December 31, 2008. These asset retirement obligations are primarily related to asbestos abatement at some of our generating facilities, the removal of oil storage tanks, equipment on leased property and environmental obligations related to the closing of ash disposal sites. In the third quarter of 2008, we revised our current cost assumption for asbestos abatement at our generating facilities based on the actual costs we have incurred as part of the decommissioning of the Lovett facility. The revision resulted in an increase to our asset retirement obligation of approximately $2 million.

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

Effect if Different Assumptions Used. We update liabilities associated with asset retirement obligations as significant assumptions change or as relevant new information becomes available. A 1% increase in our rate of inflation would result in an approximate $5 million increase to the asset retirement obligation recorded on our balance sheet as of December 31, 2008, and a 1% increase or decrease in our discount rate would result in an approximate $4 million change.

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 assets we expect to sell, at fair value less costs to sell.

Table of Contents

SFAS 144 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.

Key Assumptions and Approach Used. The determination of an impairment 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 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 reflects the risk inherent in future cash flows.

Year Ended December 31, 2008

Background

We have goodwill recorded at our Mirant Mid-Atlantic registrant on a standalone basis, which is eliminated upon consolidation at Mirant Corporation. In accordance with SFAS 142, we are required to test the goodwill balance at Mirant Mid-Atlantic at least annually. We performed the goodwill assessment at October 31, 2008, which, by policy, is our annual testing date. In conducting step one of the goodwill impairment analysis for Mirant Mid-Atlantic, we noted that the carrying value exceeded the calculated fair value of Mirant Mid-Atlantic, indicating that step two of the goodwill impairment analysis was required. Based on the results of the step one goodwill impairment analysis, we were required to test Mirant Mid-Atlantic s long-lived assets for impairment under SFAS 144 before completion of the step two test for goodwill as required under SFAS 142. As a result of the SFAS 144 assessment, we determined that no further analysis was needed as of December 31, 2008, as the undiscounted cash flows exceeded the carrying value for all asset groups reviewed by a significant amount for each asset group tested since the useful lives of the assets extend up to an additional 30 years. For additional information on the assumptions and results of the analysis see discussion below.

SFAS 144 Assumptions and Results

Our SFAS 144 assessment of the Mirant Mid-Atlantic generating facilities in the fourth quarter of 2008 included assumptions about future electricity and fuel prices, future capacity payments under the PJM RPM, the future costs of carbon under the RGGI and a subsequent federal cap-and-trade program and future capital expenditure requirements. 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. We assumed a decline in the long term price of coal from market prices observable as of the valuation date. Our long-term capacity prices are 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 further declines in reserve margins for periods beyond those for which auctions have already been completed. The costs of carbon under the RGGI were based on the September 2008 auction results, escalating annually for periods beyond 2009.

Table of Contents

We also assumed that a federal carbon cap-and-trade program would be instituted in the next several years that will replace the RGGI. Capital expenditures include those costs necessary to complete the installation of pollution control equipment to comply with the limitations for SO2, NO_x and mercury emissions under the Maryland Healthy Air Act and expenditures to maintain the operational performance of the generating facilities throughout their estimated useful lives.

For purposes of impairment testing, a long-lived asset or assets must be grouped at the lowest level of independent identifiable cash flows. Each generating facility was determined to be its own group. The leasehold improvements for each leased generating facility were determined to be their own group for impairment testing purposes.

Year Ended December 31, 2007

As a result of entering into an amendment to the 2003 Consent Decree that switched the deadlines for shutting down units 4 and 5 and an agreement with the Town of Stony Point that set the 2007 and 2008 assessed value for property tax purposes for the Lovett facility, we tested the recoverability of the Lovett facility under SFAS 144 in the second quarter of 2007. See Item 1. Business for additional information on the 2003 Consent Decree. Our estimate of cash flows related to our impairment analysis of our Lovett generating facility involved considering scenarios for the future expected operation of the Lovett facility. The most likely scenario considered was the shutdown of unit 5 by April 30, 2008, according to the amended 2003 Consent Decree. We also considered a scenario that assumed operations, utilizing coal as the primary fuel source, through 2012 to allow the Lovett facility to continue to contribute to the reliability of the electric system of the State of New York. As a result of the analysis, we recorded an impairment of long-lived assets of $175 million in the second quarter of 2007 to reduce the carrying value of the Lovett facility to its estimated fair value.

Year Ended December 31, 2006

In 2006, our assessment of the Bowline unit 3 suspended construction project resulted in the conclusion that the Bowline 3 project as configured and permitted was not economically viable. As a result of this conclusion, we determined the estimated value of the equipment and project termination liabilities. The carrying value of the development and construction costs for Bowline unit 3 exceeded the estimated undiscounted cash flows from the abandonment of the project. We recorded an impairment of $120 million, which is reflected in impairment losses on the consolidated statements of operations for the year ended December 31, 2006.

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

See Note 5 to our consolidated financial statements contained elsewhere in this report for additional information on impairments.

Pension and Other Postretirement Benefit Plans

Nature of Estimates Required. We provide pension and other postretirement benefits to certain union and non-union employees. The benefit costs associated with the pension and other postretirement benefit plans are developed from actuarial valuations. The key assumptions inherent in the actuarial valuations include the discount rate, the expected long-term rate of return on pension plan assets and the medical care cost trend rate used for other postretirement healthcare benefits. The assumptions used are subject to significant judgment and changes in the assumptions used may have a material effect on our future benefit costs.

Table of Contents

Key Assumptions and Approach Used. The discount rates used as of December 31, 2008 and 2007, were determined based on individual bond matching models comprised of portfolios of high quality corporate bonds with projected cash flows and maturity dates reflecting the time horizon during which the benefits are expected to be paid. The changes in the discount rate from period to period were the result of changes in the long-term interest rates.

The weighted average discount rates used for measuring year-end pension benefit obligations and other postretirement benefit obligations as of their respective measurement dates were as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Benefit obligation	5.40%	6.12%	5.37%	6.06%

The weighted average discount rates used for our pension benefit cost and other postretirement benefit costs during each year are shown below:

	Pension Plans Years Ended December 31,			Other Postretirement Benefit Plans Years Ended December 31,		
	2008	2007	2006	2008	2007	2006
Benefit costs	6.12%	5.66%	5.36%	6.06%	5.66%	5.36%

In determining the long-term rate of return on our pension plan assets, we evaluate current and historic market factors including inflation and interest rates. We also evaluate the portfolio by estimating the expected return on the asset mix. Our target investment allocation of our pension plan assets is 70% equity securities and 30% fixed income securities. Based on these factors, our long-term expected return on plan assets was 8.50% as of December 31, 2008 and 2007.

The medical care cost trend rate used for other postretirement healthcare benefits is the assumed long-term growth of medical costs, and is based on costs observed in the prior years.

Effect if Different Assumptions Used. The assumptions used in determining our benefit cost are subject to significant judgment and could result in material changes to our consolidated financial statements if different assumptions were used.

Pension Plans

The following table summarizes the sensitivity of our projected benefit obligation and pension benefit cost to changes in the discount rate and expected long-term rate of return on pension assets:

	Effect on projected benefit obligation at December 31, 2008	Effect on 2009 expense
	(in millions)	
Increase in discount rate 1%	$ (36.9)	$ (2.1)
Decrease in discount rate 1%	$ 45.6	$ 4.8
Increase in expected long-term rate of return 1%	N/A	$ (2.6)
Decrease in expected long-term rate of return 1%	N/A	$ 2.6

Table of Contents

Other Postretirement Benefits

The following table summarizes the sensitivity of our projected benefit obligation and other postretirement benefit cost to changes in the discount rate for our other postretirement benefits:

	Effect on projected benefit obligation at December 31, 2008	Effect on 2009 expense
	(in millions)	
Increase in discount rate 1%	$ (7.8)	$ (0.8)
Decrease in discount rate 1%	$ 9.7	$ 0.9

An annual increase or decrease in the assumed medical care cost trend rate of 1% would correspondingly increase or decrease the aggregate of the service and interest cost components of the annual postretirement benefit cost in 2008 by an inconsequential amount.

Stock-Based Compensation

Nature of Estimates Required. We account for stock-based compensation through the recognition in the statement of operations of the grant-date fair value of stock options and other equity-based compensation issued to employees and directors. We consider the assumptions inherent in our valuation and calculation of compensation expense critical to our consolidated financial statements because the underlying assumptions are subject to significant judgment and the resulting compensation expense may be material to our results of operations.

Key Assumptions and Approach Used. The Black-Scholes option-pricing model was used to measure the grant-date fair value of the stock options. The Black-Scholes model requires certain assumptions concerning implied volatility, dividend yield, expected term and grant price. These assumptions have a significant effect on the options fair value. The expected term and expected volatility often have the most effect on the fair value of the option. The inputs to the Black-Scholes model that we used for the years ended December 31, 2008 and 2007 are detailed below:

	2008		2007	
	Range	Weighted Average	Range	Weighted Average
Expected volatility	31-43%	31.2%	15-28%	19.9%
Expected dividends	%	%	%	%
Expected term				
Service condition awards	3.5 years	3.5 years	2.7 - 3.5 years	3.48 years
Performance condition awards				
Risk-free rate	2.1 - 2.9%	2.1%	4 - 4.7%	4%

We use our own implied volatility from our traded options in accordance with SAB 107. Additionally, we assume there will be no dividends paid over the expected term of the awards. As a result of our lack of exercise history, the simplified method for estimating expected term has been used in accordance with SAB 107, to the extent applicable. In accordance with SAB 110, the simplified method can continue to be applied to stock option grants after December 31, 2007. We plan to continue applying the simplified method in estimating the expected term of future stock option grants until we have sufficient exercise history. The grant price used in the Black-Scholes option pricing model is the NYSE closing price of our common stock on the day of grant. The risk-free rate for periods within the contractual term of the stock option is based on the U.S. Treasury yield curve in effect at the time of the grant.

We have determined that all of the awards granted in 2008 and 2007 qualify for equity accounting treatment. Equity accounting treatment requires awards to be measured at the grant-date fair value with compensation expense recognized over the award s requisite service period, with no subsequent re-measurement.

Table of Contents

Compensation cost has been adjusted based on estimated forfeitures. During the year ended December 31, 2008, we recognized approximately $26 million of compensation expense related to stock options, restricted shares and restricted stock units.

Effect if Different Assumptions Used. As a result of the uncertainty, complexity and judgment involved in the valuation of stock options, the assumptions related to accounting for share-based payments could result in material changes to our consolidated financial statements if different assumptions were used. A 10% increase in the volatility assumption for our valuation of stock options would have resulted in an increase of $4 million in recognized compensation expense for the year ended December 31, 2008. A 1% decrease in the forfeiture rate would result in a change of less than $1 million in the recognized compensation expense for the year ended December 31, 2008. Generally, as the expected term, expected volatility and risk-free rate increase, the option s fair value increases as a result of greater upside potential of the stock. However, as the expected dividend yield increases, the option s fair value may decrease as option holders typically do not receive dividends.

See Note 8 to our consolidated financial statements contained elsewhere in this report for additional information on stock-based compensation.

Income Taxes and Deferred Tax Asset Valuation Allowance

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

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

Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. Because of the high degree of volatility that existed in 2008 in the electricity and commodity markets in which we participate and the likelihood that economic events outside of our control may affect significantly such markets in the foreseeable future, we think that the realization of future taxable income sufficient to utilize existing deferred tax assets cannot be anticipated with the degree of confidence necessary to release the valuation allowance against such assets at this time. We evaluate this position quarterly and make our judgment based on the facts and circumstances at that time. We think that future sources of taxable income, reversing temporary differences and implemented tax planning strategies will be sufficient to realize deferred tax assets for which no valuation allowance has been established.

As of December 31, 2008, our deferred tax assets reduced by the valuation allowance are completely offset by our deferred tax liabilities. A portion of our NOLs (approximately $341 million) is attributable to tax deductions primarily related to transactions arising during the period that we were in bankruptcy. The recognition of the tax benefit of these bankruptcy period tax deductions, either through realization or reduction of the valuation allowance, will be an increase to additional paid-in-capital in stockholders equity. These NOLs will be the last utilized for financial reporting purposes. Additionally, our valuation allowance includes $35 million relating to the tax effects of other comprehensive income items primarily related to employee benefits. These other comprehensive income items will be reduced in the event that the valuation allowance is no longer required.

Under FIN 48, we must reflect in our income tax provision the full benefit of all positions that will be taken in our income tax returns, except to the extent that such positions are uncertain and fall below the recognition requirements of FIN 48. In the event that we determine that a tax position meets the uncertainty criteria of FIN 48, an additional liability or an adjustment to our NOLs, determined under the measurement criteria of FIN 48 will result. This liability or adjustment is referred to as an unrecognized tax benefit. We periodically reassess the tax positions reflected in our tax returns for open years based on the latest information available and determine whether any portion of the tax benefits reflected therein should be treated as unrecognized. The amount of the unrecognized tax benefit requires management to make significant assumptions about the expected outcomes of certain tax positions included in our filed or yet to be filed tax returns.

Effect if Different Assumptions Used. We are subject to an annual limitation on the use of pre bankruptcy emergence NOLs against current and future year taxable income in accordance with Internal Revenue Code §382(l)(6). This limitation includes the effect of net unrealized built-in gains. If a post bankruptcy ownership change within the meaning of Internal Revenue Code §382 as amended, occurs, we will be required to determine a new annual limitation that will apply to the use of all pre ownership change NOLs against taxable income arising in periods subsequent to the ownership change. As a result of changes in our stock ownership, including our repurchases of shares of our common stock since July 11, 2006, and the exercise of a significant number of warrants for our common stock during 2008, we experienced an ownership change within the meaning of Internal Revenue Code §382, as amended, in the third quarter of 2008. Our annual limitation on the amount of taxable income that can be offset by our then existing NOLs has been redetermined as of the date of that ownership change. We do not expect that the ability to offset future taxable income with existing NOLs under the redetermined annual limitation will be significantly different from our ability to do so under the annual limitation prior to the ownership change that occurred in the third quarter of 2008. However, if the Company experiences another ownership change after December 31, 2008 at or near the Company s recent stock price levels, the redetermined annual limitation could be significantly lower and could result in the payment of cash taxes above the amount currently estimated for 2009. The additional cash taxes could range from $0 to $150 million depending on the timing of the additional ownership change, if any. Beginning in 2010, tax planning strategies, including the election to amortize over five years the cost of our pollution control equipment installed pursuant to the Maryland Healthy Air Act, would be available to reduce additional cash taxes.

We continue to be under audit for multiple years by taxing authorities in various jurisdictions. Considerable judgment is required to determine the tax treatment of particular items that involve interpretations of complex tax laws. A tax liability has been recorded for certain filing positions with respect to which the outcome is uncertain and the effect is estimable. Such liabilities are based on judgment and it can take many years between the time the liability is recorded and the related filing position is no longer subject to question.

Loss Contingencies

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

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

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

Litigation

See Note 16 to our consolidated financial statements contained elsewhere in this report for further information related to our legal proceedings.

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. 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.

Table of Contents

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***
Fair Value Measurements

We are exposed to market risks associated with commodity prices, interest rates and credit risk. We adopted SFAS 157 on January 1, 2008, which affected our valuation, presentation and disclosure of derivative financial instruments used to mitigate our commodity price risk. See Note 4 to our consolidated financial statements contained elsewhere in this report for further information on the adoption of SFAS 157. We also adopted FSP FIN 39-1 on January 1, 2008, and elected to discontinue the net presentation of assets and liabilities subject to master netting agreements. See Note 2 to our consolidated financial statements contained elsewhere in this report for further information on the adoption of FSP FIN 39-1. The election to present our derivative contract assets and liabilities on a gross basis does not affect our credit risk or value at risk at December 31, 2008.

The estimated net fair value of our derivative contract assets and liabilities was a net asset of $655 million at December 31, 2008. The following table provides a summary of the factors affecting the change in fair value of the derivative contract asset and liability accounts for the year ended December 31, 2008 (in millions):

Fair value of portfolio of assets and liabilities at January 1, 2008, net(1)	$ (129)
Gains recognized in the period, net:	
New contracts and other changes in fair value(2)	583
Roll off of previous values(3)	326
Purchases, issuances and settlements(4)	(125)
Fair value of portfolio of assets and liabilities at December 31, 2008, net	$ 655

(1) Reflects our portfolio of derivative contract assets and liabilities at December 31, 2007, adjusted for a day one net gain of $1 million recognized upon adoption of SFAS 157 on January 1, 2008.

(2) 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.

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

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

The table above does not include long-term coal agreements that are not required to be recorded at fair value under SFAS 133. As such, these contracts are not included in derivative contract assets and liabilities in the accompanying consolidated balance sheets. As of December 31, 2008, these coal agreements had an estimated net fair value of approximately $38 million, which includes a credit reserve of $18 million for the estimated default risk of our coal suppliers. See *Long-Term Coal Agreement Risk* for further discussion later in this section.

As discussed in Note 2 to our consolidated financial statements contained elsewhere in this report, we did not elect the fair value option for any financial instruments under SFAS 159. However, we do transact using derivative financial instruments which are required to be recorded at fair value under SFAS 133 in our consolidated balance sheets.

Commodity Price Risk

In connection with our business of generating electricity, we are exposed to energy commodity price risk associated with the acquisition of fuel needed to generate electricity, the price of electricity produced and sold and the fair value of our fuel inventories. A portion of our fuel requirements is purchased in the spot market and a

Table of Contents

portion of the electricity we produce is sold in the spot market. In addition, the open positions in our proprietary trading and fuel oil management activities expose us to risks associated with changes in energy commodity prices.

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

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

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

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

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

Counterparty Credit Risk

The valuation of our derivative contract assets is affected by the default risk of the counterparties with which we transact. We recognized a reserve, which is reflected as a reduction of our derivative contract assets, related to counterparty credit risk of $52 million and $4 million at December 31, 2008 and 2007, respectively.

We have historically calculated the credit reserve for all of our derivative contract assets 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 accordance with SFAS 157, we calculate the credit reserve through consideration of observable market inputs, when available. In the third quarter of 2008, we changed the methodology used to calculate our credit reserve for our non-collateralized power hedges entered into by Mirant Mid-Atlantic with our major trading partners, which represents 78% of our net notional position at December 31, 2008. 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. Commencing in the third quarter of 2008, we began to calculate a credit reserve using published spreads on credit default swaps applied to our current exposure and potential loss exposure from the financial commitments in our risk management portfolio. We apply a similar approach to calculate the fair value of our coal contracts that are not included in derivative contract assets and liabilities in the 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. The change in our methodology resulted in an increase to our credit reserve at December 31, 2008, of approximately $47 million on our derivative contract assets. 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 $5 million in our credit reserve as of December 31, 2008. An increase of 10% in the spread of credit default swaps of our coal suppliers would result in an increase of $2 million in our $18 million credit reserve of our long-term coal agreements that are not included in derivative contract assets and liabilities in the accompanying consolidated balance sheets as of December 31, 2008.

The default risk for the remainder of the portfolio is generally offset by cash collateral or other credit enhancements. For the remainder of our risk management portfolio, we will continue to use published historical default probabilities to calculate a credit reserve applied to our current exposure, net of the effect of credit enhancements, and potential loss exposure from the financial commitments. Potential loss exposure is calculated as our current exposure plus a calculated five-day value at risk. 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. A downgrade of one notch in the average credit rating of our counterparties in this portion of the portfolio would result in an increase of $1 million in our credit reserve as of December 31, 2008.

Once we have delivered a physical commodity or have financially settled the credit risk, 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.

Mirant Credit Risk

In valuing our derivative contract liabilities, we apply a valuation adjustment for non-performance which is based on the probability of our default. We determine 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. The non-performance adjustment related to our credit risk at December 31, 2008 was immaterial. A downgrade of one notch in our credit rating would have an immaterial effect on our consolidated statement of operations as of December 31, 2008.

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 4 to our 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 typically 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 SFAS 157, the fair value of our derivative contract assets and liabilities is determined using bid prices for our assets and ask prices for liabilities. The quotes that we obtain from brokers are non-binding in nature, but are from brokers that typically transact in the market being quoted and are based on their knowledge of market transactions on the valuation date. We typically obtain multiple broker quotes on the valuation date for each delivery location that extend for the tenor of our underlying contracts. The number of quotes that we can obtain depends on the relative liquidity of the delivery location on the valuation date. If multiple broker quotes are received for a contract, we use an average of the quoted bid or ask prices. If only one broker quote is received for a delivery location and it cannot be validated through other external sources, we will assign the quote to a lower level within the fair value hierarchy. In some instances, we may combine broker quotes for a liquid delivery hub with broker quotes for the price spread between the liquid delivery hub and the delivery location under the contract. We also may apply interpolation techniques to value monthly strips if broker quotes are only available on a seasonal or annual basis. We perform validation procedures on the broker quotes at least on a monthly basis. The validation procedures include reviewing the quotes for accuracy and comparing them to our internal price curves. In certain instances, we may discard a broker quote if it is a clear outlier and multiple other quotes are obtained. At December 31, 2008, 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, non-current 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. Our assets and liabilities classified as Level 3 in the fair value hierarchy represent approximately 1% of our total assets and less than 1% of our total liabilities measured at fair value at December 31, 2008.

Value at Risk

Our Risk Management Policy limits our trading to certain products and contains limits and restrictions related to our asset management, proprietary trading and fuel oil management activities.

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

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

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

Table of Contents

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

	For the Years Ended December 31,	
	2008	2007
Asset Management VaR		
Year-end	$ 14	$ 20
Average	$ 18	$ 29
High	$ 21	$ 40
Low	$ 14	$ 20

The asset management VaR declined for the year ended December 31, 2008, as compared to the year ended December 31, 2007, primarily as a result of increased hedging activity against our underlying generating facilities.

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

The following table summarizes year-end, average, high and low VaR for our proprietary trading and fuel oil management operations (in millions):

	For the Years Ended December 31,	
	2008	2007
Proprietary Trading and Fuel Oil Management VaR		
Year-end	$ 1	$ 2
Average	$ 2	$ 3
High	$ 4	$ 5
Low	$ 1	$ 1

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

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 $6 million to our derivative contract assets and a decrease of $5 million to our derivative contract liabilities at December 31, 2008.

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. Assuming both are fully drawn, the amount subject to variable interest rates is approximately $1.2 billion. A 1% per annum increase in the average market rate would result in an increase in our annual interest expense of approximately $12 million.

Table of Contents

Credit Concentration Risk

We also monitor credit concentration risk on both an individual basis and a group counterparty basis. The following table highlights the credit quality and the balance sheet settlement exposures related to these activities as of December 31, 2008 (dollars in millions):

	Exposure Before Collateral(1)	Credit Collateral(2)	Exposure Net of Collateral	% of Net Exposure
Credit Rating Equivalent				
Investment grade:				
Financial institutions	$ 553	$ 20	$ 533	73%
Energy companies	232	73	159	22%
Other				
Non-investment grade:				
Financial institutions				
Energy companies				
Other				
No external ratings:				
Internally-rated investment grade	37		37	5%
Internally-rated non-investment grade	4		4	
Not internally rated				
Total	$ 826	$ 93	$ 733	100%

(1) The table excludes amounts related to contracts classified as normal purchases/normal sales and non-derivative contractual commitments that are not recorded in our consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic risk if a counterparty does not perform.

(2) Collateral includes cash and letters of credit offset by any cash collateral posted by us to a counterparty which is in excess of the amount currently owed to that counterparty.

Long-Term Coal Agreement Risk

As noted above, the credit concentration table excludes amounts related to contracts classified as normal purchases/normal sales, including our long-term coal agreements. We have non-performance risk associated with these 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 and through guarantees and other collateral arrangements when available. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers. Non-performance by our coal suppliers could have a material adverse effect on our future results of operations, financial condition and cash flows.

Item 8. ***Financial Statements and Supplementary Data***

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Mirant Corporation and subsidiaries:

We have audited the accompanying consolidated balance sheets of Mirant Corporation and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity (deficit), comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2008. We also have audited the Company s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting included within Item 9A. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mirant Corporation and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with United States generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

Table of Contents

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements,* the measurement provisions of Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit and Other Postretirement Plans*, and FASB Staff Position FIN 39-1, *Amendment of FASB Interpretation No. 39*, in 2008. As discussed in Note 7 to the consolidated financial statements, the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes,* in 2007

/s/ KPMG LLP

Atlanta, Georgia
February 26, 2009

Table of Contents

MIRANT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2008	2007	2006
	(in millions, except per share data)		
Operating revenues (including unrealized gains (losses) of $840 million, $(564) million and $757 million, respectively)	**$ 3,188**	$ 2,019	$ 3,087
Cost of fuel, electricity and other products (including unrealized (gains) losses of $54 million, $(28) million and $102 million, respectively)	**1,059**	912	1,151
Gross Margin (excluding depreciation and amortization)	**2,129**	1,107	1,936
Operating Expenses:			
Operations and maintenance	**683**	707	592
Depreciation and amortization	**144**	129	137
Impairment losses		175	119
Gain on sales of assets, net	**(39)**	(45)	(49)
Total operating expenses	**788**	966	799
Operating Income	**1,341**	141	1,137
Other Expense (Income), net:			
Interest expense	**189**	247	289
Interest income	**(70)**	(202)	(76)
Gain on sales of investments, net			(76)
Other, net	**5**	(344)	(38)
Total other expense (income), net	**124**	(299)	99
Income From Continuing Operations Before Reorganization Items, Net and Income Taxes	**1,217**	440	1,038
Reorganization items, net		(2)	(164)
Provision (benefit) for income taxes	**2**	9	(550)
Income From Continuing Operations	**1,215**	433	1,752
Income From Discontinued Operations, net	**50**	1,562	112
Net Income	**$ 1,265**	$ 1,995	$ 1,864
Basic EPS:			
Basic EPS from continuing operations	**$ 6.53**	$ 1.72	$ 6.15
Basic EPS from discontinued operations	**0.27**	6.20	0.39
Basic EPS	**$ 6.80**	$ 7.92	$ 6.54
Diluted EPS:			
Diluted EPS from continuing operations	**$ 6.11**	$ 1.56	$ 5.90
Diluted EPS from discontinued operations	**0.25**	5.64	0.38
Diluted EPS	**$ 6.36**	$ 7.20	$ 6.28

Weighted average shares outstanding	**186**	252	285
Effect of dilutive securities	**13**	25	12
Weighted average shares outstanding assuming dilution	**199**	277	297

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

F-3

Table of Contents

MIRANT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	At December 31, 2008	2007
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 1,831**	$ 4,961
Funds on deposit	**204**	304
Receivables, net	**761**	589
Derivative contract assets	**2,582**	687
Inventories	**238**	357
Prepaid expenses	**132**	142
Total current assets	**5,748**	7,040
Property, Plant and Equipment, net	**3,215**	2,590
Noncurrent Assets:		
Intangible assets, net	**196**	206
Derivative contract assets	**585**	153
Deferred income taxes	**565**	240
Prepaid rent	**258**	234
Other	**121**	75
Total noncurrent assets	**1,725**	908
Total Assets	**$ 10,688**	$ 10,538
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	**$ 46**	$ 142
Accounts payable and accrued liabilities	**894**	718
Derivative contract liabilities	**2,268**	709
Deferred income taxes	**565**	240
Other	**11**	12
Total current liabilities	**3,784**	1,821
Noncurrent Liabilities:		
Long-term debt	**2,630**	2,953
Derivative contract liabilities	**244**	261
Asset retirement obligations	**40**	44
Pension and other postretirement obligations	**148**	101
Other	**80**	48
Total noncurrent liabilities	**3,142**	3,407
Commitments and Contingencies		
Stockholders Equity:		
Preferred stock, par value $.01 per share, authorized 100,000,000 shares, no shares issued at December 31, 2008 and 2007		
Common stock, par value $.01 per share, authorized 1.5 billion shares, issued 310,666,240 and 301,196,073 at December 31, 2008 and 2007, respectively, and outstanding 144,629,446 shares and 221,811,972 at December 31, 2008 and 2007, respectively	**3**	3
Treasury stock, at cost, 166,036,794 shares and 79,384,101 shares at December 31, 2008 and 2007, respectively	**(5,330)**	(2,586)
Additional paid-in capital	**11,401**	11,357

Accumulated deficit	**(2,222)**	(3,486)
Accumulated other comprehensive income (loss)	**(90)**	22
Total stockholders equity	**3,762**	5,310
Total Liabilities and Stockholders Equity	**$ 10,688**	$ 10,538

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

Table of Contents

MIRANT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (DEFICIT)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)
			(in millions)		
Balance, December 31, 2005	$ 3	$	$ 11,298	$ (7,462)	$ 17
Net income				1,864	
Share repurchases		(1,261)			
Stock-based compensation			17		
Exercise of warrants			2		
Other comprehensive loss					(25)
Adoption of SFAS 158, net of tax					(10)
Balance, December 31, 2006	3	(1,261)	11,317	(5,598)	(18)
Net income				1,995	
Share repurchases		(1,325)			
Stock-based compensation			29		
Exercises of stock options and warrants			11		
Adoption of FIN 48				117	
Other comprehensive income					40
Balance, December 31, 2007	3	(2,586)	11,357	(3,486)	22
Net income				1,265	
Share repurchases		(2,744)			
Stock-based compensation			26		
Exercises of stock options and warrants			18		
Adoption of SFAS 157				1	
SFAS 158 measurement date transition				(2)	(1)
Other comprehensive loss					(111)
Balance, December 31, 2008	**$ 3**	**$ (5,330)**	**$ 11,401**	**$ (2,222)**	**$ (90)**

MIRANT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Years Ended December 31, 2008	2007	2006
	(in millions)		
Net Income	**$ 1,265**	$ 1,995	$ 1,864
Other comprehensive income (loss), net of tax			
Cumulative translation adjustment		4	2
Unrealized losses on available-for-sale securities			(27)
Pension and other postretirement benefits	**(111)**	36	
Other comprehensive income (loss), net of tax	**(111)**	40	(25)

Total Comprehensive Income	**$ 1,154**	$ 2,035	$ 1,839

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

Table of Contents

MIRANT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 2008	2007	2006
		(in millions)	
Cash Flows from Operating Activities:			
Net income	**$ 1,265**	$ 1,995	$ 1,864
Income from discontinued operations	**50**	1,562	112
Income from continuing operations	**1,215**	433	1,752
Adjustments to reconcile net income from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	**148**	139	147
Impairment losses		175	119
Gain on sales of assets and investments, net	**(39)**	(45)	(125)
Derivative contract activities, net	**(786)**	536	(655)
Deferred income taxes			(552)
Stock-based compensation	**25**	25	17
Non-cash gain on property tax settlement			(71)
Postretirement benefits curtailment gain	**(5)**	(32)	
Settlement of the Back-to-Back Agreement with Pepco		(341)	
Lower of cost or market inventory adjustment	**65**	7	80
Other, net	**4**	1	(33)
Changes in operating assets and liabilities:			
Receivables, net	**(213)**	184	152
Funds on deposit	**104**	(69)	456
Inventories	**47**	(77)	(89)
Other assets	**(29)**	57	(80)
Accounts payable and accrued liabilities	**220**	(128)	(218)
Settlement of claims payable	**(16)**	(53)	(814)
Other liabilities	**(63)**	(26)	51
Total adjustments	**(538)**	353	(1,615)
Net cash provided by operating activities of continuing operations	**677**	786	137
Net cash provided by operating activities of discontinued operations	**50**	178	432
Net cash provided by operating activities	**727**	964	569
Cash Flows from Investing Activities:			
Capital expenditures	**(731)**	(588)	(139)
Proceeds from the sales of assets and other investments	**42**	57	143
Restricted deposit payments and other	**(30)**	7	1
Net cash provided by (used in) investing activities of continuing operations	**(719)**	(524)	5
Net cash provided by (used in) investing activities of discontinued operations	**25**	5,281	(163)
Net cash provided by (used in) investing activities	**(694)**	4,757	(158)
Cash Flows from Financing Activities:			
Share repurchases	**(2,761)**	(1,308)	(1,261)
Proceeds from issuance of long-term debt			2,017
Repayments and purchases of long-term debt	**(420)**	(180)	(475)
Proceeds from exercises of stock options and warrants	**18**	11	2
Settlement of debt under the Plan			(990)

Debt issuance costs			(51)
Net cash used in financing activities of continuing operations	**(3,163)**	(1,477)	(758)
Net cash provided by (used in) financing activities of discontinued operations		(669)	181
Net cash used in financing activities	**(3,163)**	(2,146)	(577)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		1	
Net Increase (Decrease) in Cash and Cash Equivalents	**(3,130)**	3,576	(166)
Cash and Cash Equivalents, beginning of period	**4,961**	1,139	1,068
Plus: Cash and Cash Equivalents in Assets Held for Sale, beginning of period		246	483
Less: Cash and Cash Equivalents in Assets Held for Sale, end of period			246
Cash and Cash Equivalents, end of period	**$ 1,831**	$ 4,961	$ 1,139
Supplemental Cash Flow Disclosures:			
Cash paid for interest, net of amounts capitalized	**$ 175**	$ 346	$ 372
Cash paid for income taxes net of refunds received	**$**	$ 33	$ 165
Cash paid for claims and professional fees from bankruptcy	**$ 17**	$ 63	$ 1,908

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

Table of Contents

MIRANT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2008, 2007 and 2006

1. Description of Business and Organization

Mirant is a competitive energy company that produces and sells electricity in the United States. The Company owns or leases 10,112 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.

Mirant Corporation was incorporated in Delaware on September 23, 2005. Pursuant to the Plan for Mirant and certain of its subsidiaries, on January 3, 2006, New Mirant emerged from bankruptcy and acquired substantially all of the assets of Old Mirant, a corporation that was formed in Delaware on April 3, 1993, and that had been named Mirant Corporation prior to January 3, 2006. The Plan provides that New Mirant has no successor liability for any unassumed obligations of Old Mirant. Old Mirant was then renamed and transferred to a trust, which is not affiliated with New Mirant.

In the third quarter of 2006, the Company commenced separate auction processes to sell its Philippine (2,203 MW) and Caribbean (1,050 MW) businesses and six U.S. natural gas-fired facilities totaling 3,619 MW, consisting of the Zeeland, West Georgia, Shady Hills, Sugar Creek, Bosque and Apex facilities. On May 1, 2007, the Company completed the sale of the six U.S. natural gas-fired facilities. On June 22, 2007, the Company completed the sale of its Philippine business. On August 8, 2007, the Company completed the sale of its Caribbean business. In addition, on May 7, 2007, the Company completed the sale of Mirant NY-Gen (121 MW). After transaction costs and repayment of debt, the net proceeds to Mirant from dispositions completed in the year ended December 31, 2007, were approximately $5.071 billion. See Note 11 for additional information regarding the accounting for these businesses and facilities as discontinued operations.

On November 9, 2007, Mirant announced that it planned to return a total of $4.6 billion of excess cash to its stockholders based on four factors: (1) the outlook for the business, (2) preserving the Company s credit profile, (3) maintaining adequate liquidity, including for capital expenditures and (4) maintaining sufficient working capital. On September 22, 2008, Mirant announced that it had returned $3.856 billion of cash to its stockholders through purchases of 110 million shares of its common stock and suspended its program to return excess cash to its stockholders based on the Company s evaluation of the four factors that were set out upon commencement of the share repurchase program. On November 7, 2008, Mirant announced that it was resuming its program of returning excess cash to its stockholders and would purchase an additional $200 million of shares through open market purchases. This $200 million was completed in the fourth quarter of 2008 and was in addition to the previous $3.856 billion of cash returned to stockholders. Between November 2007 and December 2008, Mirant returned approximately $4.056 billion of cash to its stockholders through purchases of 122 million shares of its common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion. Mirant has repurchased approximately 48% of the 256 million basic shares that it had outstanding when the program began in November 2007. See Note 13 for further discussion of the share repurchases.

2. Accounting and Reporting Policies

Basis of Presentation

The accompanying consolidated financial statements of Mirant and its wholly-owned subsidiaries have been prepared in accordance with GAAP.

Table of Contents

The accompanying consolidated financial statements include the accounts of Mirant and its wholly-owned and controlled majority-owned subsidiaries as well as a VIE in which Mirant has an interest and is the primary beneficiary. The financial statements have been prepared from records maintained by Mirant and its subsidiaries in their respective countries of operation. All significant intercompany accounts and transactions have been eliminated in consolidation. As of December 31, 2008, substantially all of Mirant s subsidiaries are wholly-owned and located in the United States. The Company s obligations to MC Asset Recovery result in its treatment as a VIE in which Mirant is the primary beneficiary as defined in FIN 46R. The entity, therefore, is included in the Company s consolidated financial statements. See Note 16 for further discussion of MC Asset Recovery.

All amounts are presented in U.S. dollars unless otherwise noted. In accordance with SFAS 144, the results of operations of the Company s businesses and facilities that have been disposed of and have met the criteria for such classification, have been reclassified to discontinued operations. Certain prior period amounts have been reclassified to conform to the current year financial statement presentation.

Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make a number of estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. Mirant s significant estimates include:

- determining the fair value of certain derivative contracts;
- estimating future taxable income in evaluating its deferred tax asset valuation allowance;
- estimating the useful lives of long-lived assets;
- determining the value of asset retirement obligations;
- estimating future cash flows in determining impairments of long-lived assets and definite-lived intangible assets;
- estimating the expected return on plan assets, discount rates and other actuarial assumptions used in estimating pension and other postretirement benefit plan liabilities;
- estimating losses to be recorded for contingent liabilities; and
- estimating certain assumptions used in the grant date fair value of stock options.

Revenue Recognition

Mirant recognizes revenue from the sale of energy when earned and collection is probable. Some sales of energy are based on economic dispatch, or as-ordered by an ISO or RTO, based on member participation agreements, but without an underlying contractual commitment. ISO and RTO revenues and revenues from sales of energy based on economic-dispatch are recorded on the basis of MWh delivered, at the relevant day-ahead or real-time prices. In accordance with EITF 02-3, physical transactions, or revenues from the sale of generated electricity to ISOs and RTOs are recorded on a gross basis in the consolidated statement of operations. Financial transactions, or the buying and selling of energy for trading purposes, are recorded on a net basis in the consolidated statement of operations. When a long-term electric power agreement conveys to the buyer of the electric power the right to use the generating capacity of Mirant s facility, that agreement is evaluated to determine if it is a lease of the generating facility rather than a sale of electric power. Operating lease revenue for the Company s generating facilities is normally recorded as capacity revenue and included in operating revenues in the consolidated statements of operations. Capacity revenue also consists of revenue received from an ISO or RTO based on auction results or negotiated contract prices for making installed generation capacity available to meet system reliability requirements.

Table of Contents

Cost of Fuel, Electricity and Other Products

Cost of fuel, electricity and other products on the Company s consolidated statements of operations includes the costs of goods produced and sold, and services rendered during a reporting period, purchased emissions allowances for SO2 and NOx and the settlements of and changes in fair value of derivative financial instruments used to hedge fuel economically. Cost of fuel, electricity and other products excludes depreciation and amortization. Gross margin is total operating revenues less cost of fuel, electricity and other products.

Derivative Financial Instruments

Derivative financial instruments are recorded in the accompanying consolidated balance sheets at fair value as either derivative contract assets or liabilities, and changes in fair value are recognized currently in earnings, unless the Company elects to apply fair value or cash flow hedge accounting based on meeting specific criteria in SFAS 133. For the years ended December 31, 2008, 2007 and 2006, the Company did not have any derivative financial instruments that it had designated as fair value or cash flow hedges for accounting purposes. Mirant s derivative financial instruments are categorized by the Company based on the business objective the instrument is expected to achieve: asset management, proprietary trading or fuel oil management. All derivative financial instruments are recorded at fair value, except for certain transactions that qualify for the normal purchases or normal sales exclusion under SFAS 133 and therefore qualify for the use of accrual accounting.

As the Company s derivative financial instruments have not been designated as hedges for accounting purposes, changes in such instruments fair values are recognized immediately in earnings. For asset management activities, changes in fair value of electricity derivative financial instruments are reflected in operating revenue and changes in fair value of fuel derivative financial instruments are reflected in cost of fuel, electricity and other products in the accompanying consolidated statements of operations. Changes in the fair value and settlements of derivative financial instruments for proprietary trading and fuel oil management activities are recorded on a net basis as operating revenue in the accompanying consolidated statements of operations.

Concentration of Revenues

In 2008, 2007 and 2006, Mirant earned a significant portion of its operating revenue and gross margin from the PJM energy market, where its Mirant Mid-Atlantic generating facilities are located. Mirant Mid-Atlantic s revenues and gross margin as a percentage of Mirant s total revenues and gross margin from continuing operations are as follows:

	Years Ended December 31,		
	2008	**2007**	**2006**
Operating revenues	72%	56%	62%
Gross margin	81%	55%	68%

Coal Supplier Concentration Risk

The Company procures most of its coal supply from a small number of strategic suppliers. In order to mitigate the risk of non-performance, the Company manages its concentration levels to individual suppliers and mines. At December 31, 2008, two of the Company s coal suppliers together represented approximately 50% of the Company s expected coal purchases for 2009.

Concentration of Labor Subject to Collective Bargaining Agreements

At December 31, 2008, approximately 47% of Mirant s employees are subject to collective bargaining agreements, of which 68% are subject to the collective bargaining agreement in the Mid-Atlantic region.

Cash and Cash Equivalents

Mirant considers all short-term investments with an original maturity of three months or less to be cash equivalents. At December 31, 2008, except for amounts held in bank accounts to cover current payables, all of the Company s cash and cash equivalents were invested in AAA-rated U.S. Treasury money market funds.

Restricted Cash

Restricted cash is included in current and noncurrent assets as funds on deposit and other noncurrent assets in the accompanying consolidated balance sheets. At December 31, 2008, current and noncurrent funds on deposit were $204 million and $48 million, respectively. At December 31, 2007, current and noncurrent funds on deposit were $304 million and $7 million, respectively. Restricted cash includes deposits with brokers and cash collateral posted with third parties to support the Company s commodity positions as well as $122 million and $200 million deposits as of December 31, 2008 and 2007, respectively, by Mirant North America posted under its senior secured term loan to support the issuance of letters of credit.

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. Fuel stock is removed from the inventory account as it is used in the production of electricity. Materials and supplies are removed from the inventory account when they are used for repairs, maintenance or capital projects. Purchased emissions allowances cost is computed on an average cost basis. Purchased emissions allowances are removed from inventory and charged to cost of fuel, electricity and other products in the accompanying consolidated statements of operations as they are utilized against emissions volumes that exceed the allowances granted to the Company by the EPA.

Inventories at December 31, 2008 and 2007, consisted of (in millions):

	At December 31,	
	2008	**2007**
Fuel stock:		
Fuel oil	$ 113	$ 242
Coal	43	38
Other	1	
Materials and supplies	63	67
Purchased emissions allowances	18	10
Total inventories	$ 238	$ 357

In 2008, the Company recognized lower of cost or market inventory adjustments of $65 million, including $54 million in the fourth quarter of 2008 as a result of a decrease in fuel oil prices.

Granted Emissions Allowances

Included in property, plant and equipment are: (1) emissions allowances granted by the EPA that were projected to be required to offset physical emissions; and (2) emissions allowances granted by the EPA that were projected to be in excess of those required to offset physical emissions related to generating facilities owned by the Company. These emissions allowances were recorded at fair value at the date of the acquisition of the facility and are depreciated on a straight-line basis over the estimated useful life of the respective generating facility and are charged to depreciation and amortization expense in the accompanying consolidated statements of operations.

Included in other intangible assets are emissions allowances related to the Dickerson and Morgantown generating facilities leased by the Company. Emissions allowances related to leased generating facilities are

recorded at fair value at the commencement of the lease. These emissions allowances are amortized on a straight-line basis over the term of the lease for leased generating facilities, and are charged to depreciation and amortization expense in the accompanying consolidated statements of operations.

As a result of the capital expenditures Mirant is incurring to comply with the requirements of the Maryland Healthy Air Act, the Company anticipates that it will have significant excess SO2 and NOx emissions allowances in future periods. The Company plans to continue to maintain some SO2 and NOx emissions allowances in excess of expected generation in case its actual generation exceeds its current forecasts for future periods and for possible future additions of generating capacity. During the fourth quarter of 2007, the Company began a program to sell excess SO2 and NOx emissions allowances dependent upon market conditions.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost, which includes materials, labor, associated payroll-related and overhead costs and the cost of financing construction. The cost of routine maintenance and repairs, such as inspections and corrosion removal, and the replacement of minor items of property are charged to expense as incurred. Certain expenditures incurred during a major maintenance outage of a generating facility are capitalized, including the replacement of major component parts and labor and overhead incurred to install the parts. Depreciation of the recorded cost of depreciable property, plant and equipment is determined using primarily composite rates. Leasehold improvements are depreciated over the shorter of the expected life of the related equipment or the lease term. Upon the retirement or sale of property, plant and equipment, the cost of such assets and the related accumulated depreciation are removed from the consolidated balance sheets. No gain or loss is recognized for ordinary retirements in the normal course of business since the composite depreciation rates used by Mirant take into account the effect of interim retirements.

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 years ended December 31, 2008, 2007 and 2006, the Company incurred the following interest costs (in millions):

	Years Ended December 31,		
	2008	2007	2006
Total interest costs	$ 237	$ 272	$ 298
Capitalized and included in property, plant and equipment, net	(48)	(25)	(9)
Interest expense	$ 189	$ 247	$ 289

The amounts of capitalized interest above include interest accrued. For the years ended December 31, 2008, 2007 and 2006, cash paid for interest was $223 million, $374 million and $378 million, respectively, of which $48 million, $28 million and $6 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.

Table of Contents

Operating Leases

Mirant leases various assets under non-cancelable leasing arrangements, including generating facilities, office space and other equipment. The rent expense associated with leases that qualify as operating leases is recognized on a straight-line basis over the lease term within operations and maintenance expense in the consolidated statements of operations. The Company s most significant operating leases are Mirant Mid-Atlantic s leases of the Dickerson and Morgantown baseload units, which expire in 2029 and 2034, respectively. Mirant has an option to extend these leases. Any extensions of the respective leases would be for less than 75% of the economic useful life of the facility, as measured from the beginning of the original lease term through the end of the proposed remaining lease term. As of December 31, 2008, the total notional minimum lease payments for the remaining terms of the leases of the Dickerson and Morgantown baseload units aggregated approximately $2.0 billion. The capital expenditures associated with the leased units of Dickerson and Morgantown are included as leasehold improvements in property, plant and equipment on the accompanying consolidated balance sheets. Payments made under the terms of the lease agreement in excess of the amount of lease expense recognized are recorded as prepaid rent in the accompanying consolidated balance sheets. Prepaid rent attributable to periods beyond one year is included in noncurrent assets.

Intangible Assets

Intangible assets relate primarily to trading rights, development rights and emissions allowances. Intangible assets with definite useful lives are amortized on a straight-line basis to their estimated residual values over their respective useful lives ranging up to 40 years.

Investments

During the year ended December 31, 2006, the Company completed the sales of investments described below. The related gains are recorded in gain on sales of investments, net in the consolidated statements of operations.

Equity Investment in InterContinental Exchange. The Company sold its remaining investment in InterContinental Exchange for $58 million and realized a gain of $54 million.

NYMEX Seats. The Company sold its investment of two seats and shares on the NYMEX for $20 million and recognized a gain of $19 million.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis that approximates the effective interest method over the term of the related debt.

Income Taxes and Deferred Tax Asset Valuation Allowance

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

SFAS 109 requires that a valuation allowance be established when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences are deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including the Company s past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. The Company thinks that future sources of taxable income, reversing temporary differences and implemented tax planning strategies will be sufficient to realize deferred tax assets for which no valuation allowance has been established. A portion of the Company s NOLs (approximately $341 million) is attributable to excess tax deductions primarily related to bankruptcy transactions. The recognition of the tax benefit of these excess tax deductions, either through realization or reduction of the valuation allowance, will be an increase to additional paid-in-capital in stockholders equity. These NOLs will be the last utilized for financial reporting purposes. Additionally, the Company s valuation allowance includes $35 million relating to the tax effects of other comprehensive income items primarily related to employee benefits. These other comprehensive income items will be reduced in the event that the valuation allowance is no longer required.

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 SFAS 144. 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. Assets to be disposed of are separately presented in the accompanying consolidated balance sheets and are reported at the lower of the carrying amount or fair value less costs to sell, and are not depreciated. The assets and liabilities of a disposal group classified as held for sale are presented separately in the appropriate asset and liability sections of the accompanying consolidated balance sheets.

Earnings per Share

Basic earnings per share is calculated by dividing net income applicable to common stockholders by the weighted average number of common shares outstanding. Diluted earnings per share is computed using the weighted average number of shares of common stock and dilutive potential common shares, including common shares from warrants, restricted stock shares, restricted stock units and stock options using the treasury stock method.

Fair Value of Financial Instruments

SFAS 107 requires the disclosure of the fair value of all financial instruments that are not otherwise recorded at fair value in the financial statements. At December 31, 2008 and 2007, financial instruments recorded at contractual amounts that approximate fair value include cash and cash equivalents, funds on deposit, customer accounts receivable, notes receivable and accounts payable and accrued liabilities. The fair values of such items are not materially sensitive to shifts in market interest rates because of the short term to maturity of these instruments. The fair value of the Company s long-term debt is estimated using quoted market prices when available.

Recently Adopted Accounting Standards

SFAS 157. On September 15, 2006, the FASB issued SFAS 157, which established a framework for measuring fair value under GAAP and expanded its disclosure about fair value measurement. SFAS 157 required

Table of Contents

companies to disclose the fair value of their financial instruments according to a fair value hierarchy (i.e., Levels 1, 2 and 3, as defined). Additionally, companies are required to provide enhanced disclosure regarding fair value measurements in the Level 3 category, including a reconciliation of the beginning and ending balances separately for each major category of assets and liabilities accounted for at fair value. SFAS 157 was effective at the beginning of the first fiscal year after November 15, 2007. Mirant adopted the provisions of SFAS 157 on January 1, 2008, for financial instruments and nonfinancial assets and liabilities recognized or disclosed at fair value in the financial statements on a recurring basis.

SFAS 157 clarified that fair value should be measured at the exit price, which is the price to sell an asset or transfer a liability. The exit price may or may not equal the transaction price and the exit price objective applies regardless of a company s intent or ability to sell the asset or transfer the liability at the measurement date. The Company historically measured fair value using the approximate mid-point of the bid and ask prices. Upon adoption of SFAS 157, the Company began measuring fair value based on the bid or ask price from independent broker quotes for its derivative contract assets and liabilities in accordance with the exit price objective.

SFAS 157 also (a) clarified that non-performance risk, including an issuer s credit standing, should be considered when measuring liabilities at fair value, (b) precludes the use of a block discount when measuring instruments traded in an actively quoted market at fair value and (c) requires costs relating to acquiring instruments carried at fair value to be recognized as expense when incurred. SFAS 157 requires that a fair value measurement reflect the assumptions market participants would use in pricing an asset or liability based on the best available information.

SFAS 157 nullified a portion of the guidance in EITF 02-3. Under EITF 02-3, the transaction price presumption prohibited recognition of a day one gain or loss at the inception of a derivative contract unless the fair value of that derivative was substantially based on quoted prices or a valuation process incorporating observable inputs. Day one gains or losses on transactions that had been deferred under EITF 02-3 were recognized in the period that valuation inputs became observable or when the contract performed.

The provisions of SFAS 157 are applied prospectively, except for the initial effect on three specific items: (1) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price presumption under EITF 02-3, (2) existing hybrid financial instruments measured initially at fair value using the transaction price and (3) blockage factor discounts. Adjustments to these items required under SFAS 157 are recorded as a transition adjustment to beginning retained earnings in the year of adoption. Upon adoption of SFAS 157, the Company recognized a gain of approximately $1 million as a cumulative-effect adjustment to accumulated deficit on January 1, 2008. The cumulative-effect adjustment relates entirely to the recognition of inception gains and losses formerly deferred under EITF 02-3. See Note 4 for further discussion of SFAS 157.

FSP FAS 157-3. On October 10, 2008, the FASB issued FSP FAS 157-3, which clarifies the application of SFAS 157 in determining the fair value of a financial asset when the market for that asset is not active. FSP FAS 157-3 provides clarity in determining the fair value of a financial asset in a dislocated market, including the use of internal assumptions when relevant observable market inputs do not exist. Additionally, it clarified that the use of broker quotes in a market that is not active may not be the best indication of fair value, and that the nature of the quote should also be considered in the fair value measurement. FSP FAS 157-3 is effective immediately, including with respect to prior periods for which financial statements have not been issued. The Company adopted FSP FAS 157-3 effective September 30, 2008. The adoption of FSP FAS 157-3 did not affect the Company s statements of operations, financial position or cash flows.

SFAS 159. On February 15, 2007, the FASB issued SFAS 159, which permitted an entity to measure many financial instruments and certain other items at fair value by electing a fair value option. Once elected, the fair value option may be applied on an instrument by instrument basis, is irrevocable and is applied only to entire instruments. SFAS 159 also requires companies with trading and available-for-sale securities to report the

Table of Contents

unrealized gains and losses for which the fair value option has been elected within earnings for the period presented. SFAS 159 was effective at the beginning of the first fiscal year after November 15, 2007. The Company adopted SFAS 159 on January 1, 2008. The adoption of SFAS 159 did not affect the Company s statements of operations, financial position or cash flows because the Company did not elect the fair value option for any of its financial instruments.

FSP FIN 39-1. On April 30, 2007, the FASB issued FSP FIN 39-1, which amended FIN 39, to indicate that the following fair value amounts could be offset against each other if certain conditions of FIN 39 are otherwise met: (a) those recognized for derivative financial instruments executed with the same counterparty under a master netting arrangement and (b) those recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) arising from the same master netting arrangement as the derivative instruments. In addition, a reporting entity is not precluded from offsetting the derivative financial instruments if it determines that the amount recognized upon payment or receipt of cash collateral is not a fair value amount. FSP FIN 39-1 was effective at the beginning of the first fiscal year after November 15, 2007. In March 2008, the FASB issued SFAS 161 which, upon adoption, requires the presentation of disclosures for derivative and hedging activities on a gross basis. In SFAS 161, the FASB expressed the view that disclosing the fair value amounts of derivative instruments on a gross basis provides better information about how companies are managing risks. As a result, the Company reevaluated its policy related to the net presentation of the derivative contract assets and liabilities and related receivables and payables subject to master netting agreements. The Company elected to discontinue the net presentation of assets and liabilities subject to master netting agreements upon adoption of FSP FIN 39-1 on January 1, 2008. As required by FSP FIN 39-1, amounts at December 31, 2007, are also presented on a gross basis in the consolidated balance sheet for consistent presentation. As a result, total assets and total liabilities as of December 31, 2007, both increased by $1.086 billion. The change to gross presentation had no effect on net income, earnings per share or stockholders equity.

The following table sets forth the amounts as previously reported and the currently reported amounts at December 31, 2007 (in millions):

	December 31, 2007 (as previously reported)	Adjustment for gross presentation	December 31, 2007 (as currently reported)
Receivables, net	$ 297	$ 292	$ 589
Derivative contract assets, current	173	514	687
Derivative contract assets, noncurrent	30	123	153
Deferred income taxes, noncurrent	83	157	240
Accounts payable and accrued liabilities	$ 426	$ 292	$ 718
Derivative contract liabilities, current	196	513	709
Deferred income taxes, current	83	157	240
Derivative contract liabilities, noncurrent	137	124	261

At December 31, 2008, the Company had approximately $1 million of cash collateral posted with counterparties under master netting agreements that was included in funds on deposit on the consolidated balance sheet. In addition, approximately $20 million of cash collateral payable to counterparties under master netting agreements was included in accounts payable and accrued liabilities on the consolidated balance sheet.

SAB 110. On December 21, 2007, the SEC issued SAB 110, which amended SAB 107 to allow for the continued use of the simplified method to estimate the expected term in valuing stock options beyond December 31, 2007. The simplified method can only be applied to certain types of stock options for which sufficient exercise history is not available. The Company adopted SAB 110 on January 1, 2008, and will continue to use the simplified method until it has sufficient exercise history.

SFAS 158. On September 29, 2006, the FASB issued SFAS 158, which includes the requirement to measure postretirement plan assets and benefit obligations as of the date of the employer s fiscal year-end

Table of Contents

statement. This requirement is effective for fiscal years ending after December 15, 2008. The Company used a September 30 measurement date in 2007 and prior years and transitioned to a fiscal year-end measurement date at December 31, 2008. Mirant elected to use the alternative transition method under SFAS 158. This election resulted in an increase to accumulated deficit of approximately $2 million in 2008 that represents approximately one quarter of the annual net periodic benefit cost recognized in 2008.

New Accounting Standards Not Yet Adopted at December 31, 2008

In December 2007, the FASB issued SFAS 141R, which requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS 141R also requires disclosure of information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS 141R requires that acquisition-related costs be expensed as incurred. The provisions of SFAS 141R became effective for acquisitions completed on or after January 1, 2009; however, the income tax considerations included in SFAS 141R were effective as of that date for all acquisitions, regardless of the acquisition date. The Company adopted SFAS 141R on January 1, 2009. The adoption of SFAS 141R had no effect on the Company s statements of operations, financial position or cash flows.

On February 12, 2008, the FASB issued FSP FAS 157-2, which defers the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities, with the exception of those assets and liabilities that are recognized or disclosed on a recurring basis (at least annually). The Company s non-recurring nonfinancial assets and liabilities that could be measured at fair value in the Company s financial statements include long-lived asset impairments and the initial recognition of asset retirement obligations. The Company adopted FSP FAS 157-2 on January 1, 2009, and the adoption had no effect on the Company s statements of operations, financial position or cash flows. The Company will incorporate the recognition and disclosure provisions of SFAS 157 for fair value measurements for non-recurring nonfinancial assets and liabilities in future filings.

On March 19, 2008, the FASB issued SFAS 161, which amends SFAS 133 to enhance the required disclosures for derivative instruments and hedging activities. The Company utilizes derivative financial instruments to manage its exposure to commodity price risks and changes in conversion spreads and for its proprietary trading and fuel oil management activities. The Company adopted SFAS 161 on January 1, 2009, and expects to modify the presentation of the quantitative information included in its note disclosures in order to differentiate among asset management, proprietary trading and fuel oil management activities and their effect on the Company s financial statements in the Company s Form 10-Q for the first quarter of 2009.

On December 30, 2008, the FASB issued FSP FAS 132R-1, which requires enhanced disclosures about plan assets of an employer s defined benefit pension or other postretirement plan. FSP FAS 132R-1 will require additional information on how the fair value of plan assets is measured, including a reconciliation of beginning and ending balances for Level 3 inputs and the valuation techniques used to measure fair value. FSP FAS 132R-1 is effective for fiscal years ending after December 15, 2009. The Company will adopt FSP FAS 132R-1 for its defined benefit and other postretirement plans disclosures in its Form 10-K for the year ended December 31, 2009. The Company is currently evaluating the potential effect of adopting FSP FAS 132R-1 on its disclosures in the Company s consolidated financial statements.

Table of Contents

3. Accounts Receivable and Notes Receivable

Receivables consisted of the following at December 31, 2008 and 2007 (in millions):

	At December 31,	
	2008	2007
Customer accounts	$ 751	$ 542
Notes receivable	5	13
Other	18	64
Less: allowance for uncollectible accounts	(3)	(14)
Total receivables	771	605
Less: long-term receivables included in other long-term assets	(10)	(16)
Total current receivables	$ 761	$ 589

4. Financial Instruments

Derivative Financial Instruments

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 and changes in conversion spreads. 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 contracts in markets where the Company has a physical presence to attempt to generate incremental gross margin.

Adoption of SFAS 157

Effective January 1, 2008, the Company adopted SFAS 157 as discussed in Note 2, which, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. SFAS 157 clarifies that fair value should be measured at the exit price, which is the price to sell an asset or transfer a liability. In applying the exit price objective upon adoption of SFAS 157, the Company measures fair value based on the bid or ask price from independent broker quotes for its derivative contract assets and liabilities.

Derivative financial instruments are recorded at their estimated fair value in the Company s accompanying consolidated balance sheets as derivative contract assets and liabilities except for certain transactions that qualify for the normal purchases or normal sales exception election that allows for accrual accounting treatment. As defined in SFAS 157, fair value is the price that would be received from the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company utilizes certain assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market-corroborated or generally unobservable. The Company utilizes valuation techniques that attempt to maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of the fair values considers various factors, including closing exchange or OTC market price quotations, time value, credit quality, liquidity and volatility factors underlying options and contracts. The fair value of certain derivative financial instruments is estimated using pricing models based on contracts with similar terms and risks. Modeling techniques assume market correlation and volatility, such as using the prices of one delivery point to calculate the price of the contract s different delivery point. The nominal value of the transaction is discounted using a LIBOR forward interest rate curve. In addition, by applying a credit reserve which is calculated based on credit default swaps or published default probabilities for the actual and potential asset value, the fair value of Mirant s derivative financial instruments reflects the risk that the counterparties to these contracts may default on the obligations. Likewise, by applying a reserve for non-performance which is calculated based on the probability of Mirant defaulting, Mirant adjusts its derivative contract liabilities to reflect the price at which a potential market participant would be willing to assume Mirant s liabilities.

Table of Contents

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 consolidated statements of operations. Changes in the fair value and settlements of derivative financial instruments for proprietary trading and fuel oil management activities are recorded on a net basis as operating revenue in the accompanying consolidated statements of operations. As of December 31, 2008, the Company does not have any derivative financial instruments for which hedge accounting, as defined by SFAS 133, has been elected.

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 Mirant uses vary from readily observable prices for exchange-traded instruments to price curves that cannot be validated through external pricing sources. Mirant s financial assets and liabilities carried at fair value in the financial statements are classified in three categories based on the inputs used. The high-level guidelines described below are used to determine the appropriate classification of inputs within the fair value hierarchy.

Level 1 inputs Unadjusted quoted prices available in active markets for identical assets or liabilities that the Company has the ability to access and transact upon as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of natural gas and crude oil futures traded on the NYMEX and swaps cleared against NYMEX prices.

Level 2 inputs Pricing inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using quotes from independent brokers or other valuation methodologies. These include widely-accepted methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as OTC forwards, swaps and options.

Level 3 inputs Pricing inputs that are generally less observable than those from objective sources. These inputs may be used with internally developed methodologies or methodologies utilizing significant inputs that represent management s best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored. Inputs such as assumptions for market prices, supply and demand market data, correlation and volatility are used for modeling with internally developed methodologies or methodologies utilizing significant inputs that represent management s best estimate of fair value. At each balance sheet date, the Company performs an analysis of all instruments subject to SFAS 157 and includes in Level 3 all those whose fair value is based on significant unobservable inputs.

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

Table of Contents

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 December 31, 2008, by category and tenor, respectively. At December 31, 2008, the Company s only financial assets and liabilities measured at fair value on a recurring basis are derivative financial instruments.

The following table presents financial assets and liabilities, net accounted for at fair value on a recurring basis as of December 31, 2008, by category (in millions):

	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Total assets	$ 545	$ 2,575	$ 47	$ 3,167
Total liabilities	(561)	(1,950)	(1)	(2,512)
Total	$ (16)	$ 625	$ 46	$ 655

The following table presents financial assets and liabilities, net accounted for at fair value on a recurring basis as of December 31, 2008, by tenor (in millions):

	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
2009	$ (16)	$ 286	$ 45	$ 315
2010		81	1	82
2011		35		35
2012		37		37
2013		86		86
Thereafter		100		100
Total	$ (16)	$ 625	$ 46	$ 655

The volumetric weighted average maturity, or weighted average tenor, of the derivative contract portfolio at December 31, 2008 and December 31, 2007, was approximately 23 months and 12 months, respectively. The net notional amount, or net short position, of the derivative contract assets and liabilities at December 31, 2008 and December 31, 2007, was approximately 42 million equivalent MWh and 26 million equivalent MWh, respectively.

Level 3 Disclosures

The following tables present a roll forward of fair values of assets and liabilities, net categorized in Level 3 and the amount included in earnings for the year ended December 31, 2008 (in millions):

Fair value of assets and liabilities categorized in Level 3 at January 1, 2008	$ 12
Total gains or losses (realized/unrealized):	
Included in earnings of existing contracts (or changes in net assets or liabilities)[1]	(4)
Purchases, issuances and settlements[2]	21

Transfers in and /or out of Level 3[3]	17
Fair value of assets and liabilities categorized in Level 3 at December 31, 2008	$ 46

[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.

Table of Contents

(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.

	Year Ended December 31, 2008		
	Operating Revenues	Cost of Fuel	Total
Gains (losses) included in earnings	$ 46	$ (12)	$ 34
Gains (losses) included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets still held at December 31, 2008	$ 52	$ (7)	$ 45

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 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 at December 31, 2008 and 2007 are as follows (in millions):

	December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long- and short-term debt	$ 2,676	$ 2,345	$ 3,095	$ 3,009
Other:				
Notes and other receivables	$ 13	$ 12	$ 20	$ 24

5. Long-Lived Assets

Property, plant and equipment, net consisted of the following at December 31, 2008 and 2007 (dollars in millions):

	At December 31,		Depreciable
	2008	2007	Lives (years)
Production	$ 2,412	$ 2,234	14 to 46
Leasehold improvements on leased generating facilities	405	214	5 to 34
Construction work in progress	997	645	
Other	236	219	2 to 12
Less: accumulated depreciation, amortization and provision for impairment	(835)	(722)	
Total property, plant and equipment, net	$ 3,215	$ 2,590	

Table of Contents

Depreciation of the recorded cost of property, plant and equipment is recognized on a straight-line basis over the estimated useful lives of the assets. Acquired emissions allowances related to owned facilities are included in production assets above, and are depreciated on a straight-line basis over the average life of the related generating facilities. Depreciation expense was approximately $135 million, $121 million and $129 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Intangible Assets, net

Following is a summary of intangible assets at December 31, 2008 and 2007 (dollars in millions):

		At December 31, 2008		At December 31, 2007	
	Weighted Average Amortization Lives	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Trading rights	26 years	$ 27	$ (6)	$ 27	$ (5)
Development rights	38 years	62	(12)	62	(11)
Emissions allowances	31 years	150	(34)	151	(29)
Other intangibles	27 years	14	(5)	14	(3)
Total intangible assets		$ 253	$ (57)	$ 254	$ (48)

Trading rights are intangible assets recognized in connection with asset purchases that represent the Company s ability to generate additional cash flows by incorporating Mirant s trading activities with the acquired generating facilities.

Development rights represent the right to expand capacity at certain acquired generating facilities. The existing infrastructure, including storage facilities, transmission interconnections and fuel delivery systems and contractual rights acquired by Mirant, provide the opportunity to expand or repower certain generating facilities.

Emissions allowances represent allowances granted for the leasehold baseload units at the Dickerson and Morgantown facilities.

Amortization expense was approximately $9 million for the year ended December 31, 2008, and $8 million for each of the years ended December 31, 2007 and 2006. Assuming no future acquisitions, dispositions or impairments of intangible assets, amortization expense is estimated to be approximately $9 million for each of the next five years.

Impairments on Assets Held and Used

In accordance with SFAS 144, an asset classified as held and used shall be tested for recoverability whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. An asset impairment charge must be recognized if the sum of the undiscounted expected future cash flows from a long-lived asset is less than the carrying value of that asset. The amount of any impairment charge is calculated as the excess of the carrying value of the asset over its fair value. Fair value is estimated based on the discounted future cash flows from that asset or determined by other valuation techniques.

In 2000, the State of New York issued an NOV to the previous owner of the Company s Lovett facility alleging NSR violations associated with the operation of that facility prior to its acquisition by the Company. On June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into a consent decree (the 2003 Consent Decree). The 2003 Consent Decree was approved by the Bankruptcy Court on October 15, 2003. Under the 2003 Consent Decree, Mirant Lovett had three options: (1) install emissions controls on the Lovett facility s two coal-fired units (units 4 and 5); (2) shut down unit 4 and convert unit 5 to natural gas; or (3) shut down unit 5 in 2007 and unit 4 in 2008. The Company concluded that the installation of the required emissions controls was uneconomic. The Company also concluded that operating unit 5 on natural gas was uneconomic.

Table of Contents

On October 19, 2006, Mirant Lovett notified the New York Public Service Commission, the NYISO, Orange and Rockland and certain other affected transmission and distribution companies in New York of its intent to discontinue operation of units 3 and 5 of the Lovett facility in April 2007.

On May 10, 2007, Mirant Lovett entered into an amendment to the 2003 Consent Decree with the State of New York that switched the deadlines for shutting down units 4 and 5 so that the deadline for compliance by unit 5 was extended until April 30, 2008, and the deadline for unit 4 was shortened. The Company discontinued operation of unit 4 as of May 7, 2007. In addition, the Company discontinued operation of unit 3 because it was uneconomic to run the unit.

In the second quarter of 2007, the Company performed an impairment analysis of the Lovett facility and, as a result of this analysis, recorded an impairment loss of $175 million to reduce the carrying value of the Lovett facility to its estimated fair value. The carrying value of the Lovett facility prior to the impairment was approximately $185 million. The remaining depreciable life for the Lovett facility was also adjusted to April 30, 2008, based on the high likelihood of a shutdown of unit 5 on that date.

On October 20, 2007, Mirant Lovett submitted notices of its intent to discontinue operations of unit 5 of the Lovett generating facility as of midnight on April 19, 2008, to the New York Public Service Commission, the NYISO, Orange and Rockland and several other potentially affected transmission and distribution companies in New York. The Company ceased operation of unit 5 on April 19, 2008, and has substantially completed the demolition of the Lovett facility.

In 2006, the Company s assessment of the Bowline unit 3 suspended construction project resulted in the conclusion that the Bowline unit 3 project as configured and permitted was not economically viable. As a result of this conclusion, the Company determined the estimated value of the equipment and project termination liabilities. At December 31, 2006, the carrying value of the development and construction costs for Bowline unit 3 exceeded the estimated undiscounted cash flows from the abandonment of the project. The Company recorded an impairment of $120 million, which is reflected in impairment losses on the consolidated statement of operations for the year ended December 31, 2006.

6. Long-term Debt

Long-term debt at December 31, 2008 and 2007 was as follows (in millions):

	At December 31, 2008	2007	Interest Rate	Secured/ Unsecured
Long-term debt:				
Mirant Americas Generation:				
Senior notes:				
Due 2011	$ 535	$ 811	8.30%	Unsecured
Due 2021	450	450	8.50%	Unsecured
Due 2031	400	400	9.125%	Unsecured
Unamortized debt premium/discount	(3)	(3)		
Mirant North America:				
Senior secured term loan, due 2009 to 2013	415	555	LIBOR + 1.75%	Secured
Senior notes, due 2013.	850	850	7.375%	Unsecured
Capital leases, due 2009 to 2015	29	32	7.375% -8.19%	
Total	2,676	3,095		
Less: current portion of long-term debt	(46)	(142)		
Total long-term debt, excluding current portion	$ 2,630	$ 2,953		

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. In the years ended December 31, 2008 and 2007, the Company purchased and retired $276 million and $39 million, respectively, of Mirant Americas Generation senior notes due in 2011.

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 and a senior secured revolving credit facility. The senior secured term loan had an initial principal balance of $700 million, which has amortized to $415 million as of December 31, 2008. 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. Although the senior secured revolving credit facility has lender commitments of $800 million, availability thereunder reflects a $45 million reduction as a result of the expectation that Lehman Commercial Paper, Inc., which filed for bankruptcy in October 2008, will not honor its $45 million commitment under the facility. During the year ended December 31, 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 December 31, 2008, there were approximately $172 million of letters of credit outstanding under the senior secured revolving credit facility. At December 31, 2008, a total of $583 million was available under the senior secured revolving credit facility and the senior secured term loan for cash draws or for the issuance of letters of credit.

In addition to quarterly principal installments of $1.32 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 19, 2008, Mirant North America made a mandatory principal prepayment of approximately $135 million on the term loan. At December 31, 2008, the current estimate of the mandatory principal prepayment of the term loan in March 2009 is approximately $37 million. This amount has been reclassified from long-term debt to current portion of long-term debt at December 31, 2008. The primary causes of the difference between the March 2008 prepayment and the expected March 2009 prepayment are lower adjusted EBITDA and higher capital expenditures in 2008 compared to 2007.

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.

Mirant North America Senior Notes

In December 2005, Mirant North America issued senior notes in an aggregate principal amount of $850 million that bear interest at 7.375% and mature on December 31, 2013. The original senior notes were issued in a private placement and were not registered with the SEC. The proceeds of the original senior notes offering initially were placed in escrow pending the emergence of Mirant North America from bankruptcy. The proceeds were released from escrow in connection with Mirant North America s emergence from bankruptcy and the closing of the senior secured credit facilities.

In connection with the issuance of the original senior notes, Mirant North America entered into a registration rights agreement under which it agreed to complete an exchange offer for the original senior notes. On June 29, 2006, Mirant North America completed its registration under the Securities Act of $850 million of the senior notes and initiated the exchange offer. The exchange offer was completed on August 4, 2006, with $849.965 million of the outstanding original senior notes being tendered for the senior notes. The terms of the senior notes are identical in all material respects to the terms of the original senior notes, except that the senior notes are registered under the Securities Act and generally are not subject to transfer restrictions or registration rights.

Interest on the notes is payable on each June 30 and December 31. The senior notes 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. The notes are redeemable at the option of Mirant North America, in whole or in part, at any time prior to December 31, 2009, at a price equal to 100% of the principal amount, plus accrued and unpaid interest, plus a make-whole premium. At any time on or after December 31, 2009, Mirant North America may redeem the notes at specified redemption prices, together with accrued and unpaid interest, if any, to the date of redemption. Under the terms of the notes, the occurrence of a change of control will be a triggering event requiring Mirant North America to offer to purchase all or a portion of the notes at a price equal to 101% of their principal amount, together with accrued and unpaid interest, if any, to the date of purchase. In addition, certain asset dispositions or casualty events will be triggering events which may require Mirant North America to use the proceeds from those asset dispositions or casualty events to make an offer to purchase the notes at 100% of their principal amount, together with accrued and unpaid interest, if any, to the date of purchase if such proceeds are not otherwise used, or committed to be used, within certain time periods, to repay senior secured indebtedness, to repay indebtedness under the senior secured credit facilities (with a corresponding reduction in commitments) or to invest in capital assets related to its business.

Capital Leases

Long-term debt includes a capital lease by Mirant Chalk Point. At December 31, 2008 and 2007, the current portion of the long-term debt under this capital lease was $3 million. The amount outstanding under the capital lease, which matures in 2015, is $28 million with an 8.19% annual interest rate. This lease is of an 84 MW peaking electric power generating facility. Depreciation expense related to this lease was approximately $2 million for each of the years ended December 31, 2008, 2007 and 2006. The annual principal payments under this lease are approximately $3 million in 2009 and 2010, $4 million in 2011 and 2012, $5 million in 2013 and $9 million thereafter. The gross amount of assets under the capital lease, recorded in property, plant and equipment, net, was $24 million at December 31, 2008 and 2007. The related accumulated depreciation was $13 million and $12 million at December 31, 2008 and 2007, respectively.

Debt Maturities

At December 31, 2008, the annual scheduled maturities of debt during the next five years and thereafter were as follows (in millions):

2009	$ 46
2010	9
2011	544
2012	8
2013	1,213
Thereafter	856
Total	$ 2,676

With the exception of 2009, the annual scheduled maturities above do not include estimates of Mirant North America s required principal prepayments of its senior secured term loan based on its excess free cash flow.

Table of Contents

Sources of Funds and Capital Structure

The principal sources of liquidity for the Company s future operations and capital expenditures are expected to be: (1) existing cash on hand and cash flows from the operations of the Company s subsidiaries; (2) letters of credit issued or borrowings made under Mirant North America s senior secured revolving credit facility; and (3) letters of credit issued under Mirant North America s senior secured term loan.

The Company and certain of its subsidiaries, including Mirant Americas Generation and Mirant North America, are holding companies and, as a result, the Company and such subsidiaries are dependent upon dividends, distributions and other payments from their respective subsidiaries to generate the funds necessary to meet their obligations. The ability of certain of the Company s subsidiaries to pay dividends and make distributions is restricted under the terms of their debt or other agreements. In particular, a substantial portion of the cash from the Company s operations is generated by Mirant Mid-Atlantic. The Mirant Mid-Atlantic leveraged leases contain a number of covenants, including limitations on dividends, distributions and other restricted payments. Under its leveraged leases, Mirant Mid-Atlantic is not permitted to make any dividends, distributions and other restricted payments unless: (1) it satisfies the fixed charge coverage ratio on a historical basis for the last period of four fiscal quarters; (2) it is projected to satisfy the fixed charge coverage ratio for the next two periods of four fiscal quarters; and (3) no significant lease default or event of default has occurred and is continuing. In the event of a default under the leveraged leases or if the restricted payment tests are not satisfied, Mirant Mid-Atlantic would not be able to distribute cash. Based on the Company s calculation of the fixed charge coverage ratios under the leveraged leases as of December 31, 2008, Mirant Mid-Atlantic meets the required 1.7 to 1.0 ratio for restricted payments, both on a historical and projected basis.

Mirant North America is an intermediate holding company that is a subsidiary of Mirant Americas Generation and the parent of its indirect subsidiaries, including Mirant Mid-Atlantic. Mirant North America incurred certain indebtedness pursuant to its senior notes and senior secured credit facilities secured by the assets of Mirant North America and its subsidiaries (other than Mirant Mid-Atlantic and Mirant Energy Trading). The indebtedness of Mirant North America includes certain covenants typical in such notes and credit facilities, including restrictions on dividends, distributions and other restricted payments. Further, the notes and senior secured credit facilities include financial covenants that will exclude from the calculation the financial results of any subsidiary that is unable to make distributions or pay 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 transaction 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.

The ability of Mirant Americas Generation to pay its obligations is dependent on the receipt of dividends from Mirant North America, capital contributions from Mirant and its ability to refinance all or a portion of those obligations as they become due.

As described above, Mirant North America and Mirant Mid-Atlantic have restrictions on their ability to pay dividends or make intercompany loans and advances under their financing arrangements or other third party agreements. At December 31, 2008, 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 $354 million at Mirant North America and its subsidiaries. Of this amount, $125 million was held by Mirant Mid-Atlantic which, as of December 31, 2008, met the tests under the leveraged lease documentation permitting it to make distributions to Mirant North America. While Mirant North America is in compliance with its financial covenants, as of December 31, 2008, it is restricted from making distributions because of the free cash flow requirements under the restricted payment test of its senior credit facility. The primary factor lowering the free cash flow calculation in the restricted payment test 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. Except for permitted distributions to cover interest payable on Mirant Americas Generation s senior notes, the $3.883 billion of net assets of Mirant North America and its

Table of Contents

subsidiaries were restricted from distribution from Mirant North America to its parent, Mirant Americas Generation, as of December 31, 2008. Notwithstanding such restriction, Mirant thinks that it will have sufficient liquidity for its future operations, capital expenditures and debt service obligations from existing cash on hand, expected cash flows from the operations of its subsidiaries and the ability to issue letters of credit or make borrowings under the Mirant North America senior credit facilities.

7. Income Taxes

Income from continuing operations before income taxes for the years ended December 31, 2008, 2007 and 2006 was $1.217 billion, $442 million and $1.202 billion, respectively.

The income tax provision (benefit) from continuing operations consisted of the following (in millions):

	Years Ended December 31,		
	2008	2007	2006
Current income tax provision	$ 2	$ 9	$ 2
Deferred income tax provision (benefit)			(552)
Provision (benefit) for income taxes	$ 2	$ 9	$ (550)

A reconciliation of the Company s federal statutory income tax provision to the effective income tax provision adjusted for permanent and other items for the years ended December 31, 2008, 2007 and 2006, is as follows (in millions):

	Years Ended December 31,		
	2008	2007	2006
Provision (benefit) for income taxes based on United States federal statutory income tax rate	$ 426	$ 154	$ 419
State and local income tax (benefit), net of federal income taxes	119	(95)	79
Discontinued operations	18	21	(64)
Return to provision adjustments:			
Professional fees during bankruptcy			65
Previously deferred intercompany gain			22
Foreign reorganization gain			83
Other		(86)	50
Effect of Internal Revenue Code Section §382(1)(6) and §382(1)(5)		(321)	297
Effect of implementing FIN 48		44	
Effect of other comprehensive income transactions	(35)		
Reorganization adjustments		(170)	
Taxes accrued on foreign earnings			16
Excess tax deductions related to bankruptcy transactions		(212)	(22)
Change in deferred tax asset valuation allowance	(528)	671	(1,513)
Other differences, net	2	3	18
Tax provision (benefit)	$ 2	$ 9	$ (550)

Table of Contents

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their respective tax bases which give rise to deferred tax assets and liabilities for continuing operations are as follows (in millions):

	December 31, 2008	December 31, 2007
Deferred Tax Assets:		
Employee benefits	$ 96	$ 64
Reserves	17	16
Loss carry forwards	1,355	1,464
Property and intangible assets	17	141
Derivative contracts		52
Other	77	88
Subtotal	1,562	1,825
Valuation allowance	(1,258)	(1,786)
Net deferred tax assets	304	39
Deferred Tax Liabilities:		
Derivative contracts	(267)	
Other	(37)	(39)
Net deferred tax liabilities	(304)	(39)
Net deferred taxes	$	$

NOLs

As required by applicable accounting principles, an enterprise that anticipates the realization of a pre-tax gain must recognize the benefit or detriment of the deferred tax assets and liabilities associated with the transaction in the year in which it becomes more likely than not that the gain will be realized. In accordance with EITF 93-17, *Recognition of Deferred Tax Assets for a Parent Company s Excess Tax Basis in the Stock of a Subsidiary that Is Accounted for as a Discontinued Operation*, the Company recognized a tax benefit in 2006 arising from and related solely to the sale of the Philippine business. Conversely, in 2007, the Company recognized an income tax provision of $721 million that arose from and was specifically related to the sale of the Philippine business. The entire amount of this provision was recorded in income from discontinued operations in the consolidated statement of operations for the year ended December 31, 2007.

As a result of changes in the Company s stock ownership, including the Company s repurchases of shares of its common stock since July 11, 2006, and the exercise of a significant number of warrants for Mirant common stock during 2008, in the third quarter, the Company experienced an ownership change within the meaning of Internal Revenue Code Section (§) 382 of the Internal Revenue Code of 1986, as amended. The Company s annual limitation on the amount of taxable income that can be offset by the Company s then existing NOLs has been redetermined as of the date of the ownership change. The Company does not expect that the ability to offset future taxable income with existing NOLs under the redetermined annual limitation will be significantly different from the Company s ability to do so under the annual limitation prior to the ownership change that occurred in the third quarter of 2008. However, if the Company experiences another ownership change after December 31, 2008 at or near the Company s recent stock price levels, the redetermined annual limitation could be significantly lower and could result in the payment of cash taxes above the amount currently estimated for 2009. Beginning in 2010, tax planning strategies, including the election to amortize over five years the cost of the Company s pollution control equipment installed pursuant to the Maryland Healthy Air Act, would be available to reduce additional cash taxes.

The December 31, 2008, federal NOL carry forward for financial reporting was $3.1 billion with expiration dates from 2022 to 2026. Similarly, there is an aggregate amount of $5.3 billion of state NOL carry forwards with various expiration dates (based on the company s review of the application of apportionment factors and other state tax limitations).

Table of Contents

SFAS 109 requires that a valuation allowance be established when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences are deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including the Company s past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

Objective positive evidence is necessary to support a conclusion that a valuation allowance is not needed for all or a portion of deferred tax assets when significant negative evidence exists. The Company evaluates this position quarterly and makes its judgment based on the facts and circumstances at that time. The Company thinks that future sources of taxable income, reversing temporary differences and implemented tax planning strategies will be sufficient to realize deferred tax assets for which no valuation allowance has been established.

As of December 31, 2008, the Company s deferred tax assets reduced by the valuation allowance are completely offset by its deferred tax liabilities. A portion of the Company s NOLs (approximately $341 million) is attributable to tax deductions primarily related to transactions arising during the period that the Company was in bankruptcy. The recognition of the tax benefit of these bankruptcy period tax deductions, either through realization or reductions of the valuation allowance, will be an increase to additional paid-in-capital in stockholders equity. These NOLs will be the last utilized for financial reporting purposes. Additionally, the Company s valuation allowance includes $35 million relating to the tax effects of other comprehensive income items primarily related to employee benefits. These other comprehensive income items will be reduced in the event that the valuation allowance is no longer required.

Tax Uncertainties

The Company adopted the provisions of FIN 48 on January 1, 2007. Prior to adoption of FIN 48, Mirant recognized contingent liabilities related to tax uncertainties when it was probable that a loss had occurred and the loss or range of loss could be reasonably estimated. The recognition of contingent losses for tax uncertainties required management to make significant assumptions about the expected outcomes of certain tax contingencies. Under FIN 48, the Company must reflect in its income tax provision the full benefit of all positions that will be taken in the Company s income tax returns, except to the extent that such positions are uncertain and fall below the recognition requirements of FIN 48. In the event that the Company determines that a tax position meets the uncertainty criteria of FIN 48, an additional liability or an adjustment to the Company s NOLs, determined under the measurement criteria of FIN 48 will result. The Company periodically reassesses the tax positions in its tax returns for open years based on the latest information available and determines whether any portion of the tax benefits reflected should be treated as unrecognized. As a result of applying the criteria under FIN 48, for continuing operations, the Company recognized at adoption a decrease in accrued liabilities of $61 million and an increase of $26 million in taxes receivable. For discontinued operations, the adoption of FIN 48 resulted in a decrease in liabilities held for sale and accumulated deficit of $30 million. The total effect of adopting FIN 48 was an increase in stockholders equity of $117 million. A reconciliation of the beginning and ending amount of unrecognized tax benefits for continuing operations is as follows (in millions):

	For the Years Ended December 31,	
	2008	2007
Unrecognized tax benefits, January 1	$ 15	$ 13
Increases based on tax positions related to the current year		
Increases for tax positions for prior years		2
Settlements	(2)	
Lapse of statute of limitations		
Unrecognized tax benefits, December 31	$ 13	$ 15

The unrecognized tax benefits included the review of tax positions relating to open tax years beginning in 1999 and continuing to the present. The Company s major tax jurisdictions are the United States at the federal level and multiple state jurisdictions. For United States federal income taxes, all tax years subsequent to 2004 remain open and for state income taxes, the earliest open year is 1999. However, both the federal and state NOL carry forwards from any closed year are subject to examination until the year that such NOL carry forwards are utilized and that year is closed for audit. The Company does not anticipate any significant changes in its unrecognized tax benefits over the next 12 months. Included in the balance at December 31, 2008 and 2007, the Company had $2 million and $4 million, respectively, of unrecognized tax benefits that would affect the effective tax rate if they were recognized. The Company s tax provision includes an immaterial amount related to the accrual for any penalties and interest subsequent to its adoption of FIN 48.

8. Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

Mirant provides pension benefits to its non-union and union employees through various defined benefit and defined contribution pension plans. These benefits are based on pay, service history and age at retirement. Defined benefit pensions are not provided for non-union employees hired after April 1, 2000, who participate in a profit sharing arrangement. Most pension benefits are provided through tax-qualified plans that are funded in accordance with ERISA and Internal Revenue Service requirements. Certain executive pension benefits that cannot be provided by the tax-qualified plans are provided through unfunded non-tax-qualified plans. The measurement dates for the defined benefit plans were December 31 for 2008 and September 30 for 2007 and 2006.

Mirant also provides certain medical care and life insurance benefits for eligible retired employees which are accounted for on an accrual basis using an actuarial method that recognizes the net periodic costs as employees render service to earn the postretirement benefits. The measurement dates for these postretirement benefit plans were December 31 for 2008 and September 30 for 2007 and 2006.

During the fourth quarter of 2006, Mirant amended the postretirement benefit plan covering non-union employees to eliminate all employer provided subsidies through a gradual phase-out by 2011. As a result, Mirant recognized a reduction in other postretirement liabilities of $32 million. Since the amendment occurred after the 2006 measurement date, the plan curtailment was recognized during the first quarter of 2007 as a reduction in operations and maintenance expense for the year ended December 31, 2007.

During the second quarter of 2008, Mirant severed certain employees as a result of the shutdown of the Lovett facility. As a result, the Company recognized a curtailment gain of approximately $5 million for its pension and postretirement benefits plans which was reflected as a reduction of operations and maintenance expense for the year ended December 31, 2008.

SFAS 158 is designed to improve financial reporting by requiring an employer to recognize the overfunded or underfunded status of pension, retiree medical and other postretirement benefit plans on its balance sheets rather than only disclosing the funded status in the financial statement footnotes. The Company adopted SFAS 158 on December 31, 2006, and recognized an increase in other noncurrent liabilities of $21 million related to its underfunded defined benefit pension plans and recognized a decrease in other noncurrent liabilities of $5 million related to its other postretirement benefit plans. Effective December 31, 2008, SFAS 158 also requires that companies measure the funded status of plans as of the year-end balance sheet date. Mirant historically used September 30 as the date to measure the funded status of its plans. SFAS 158 offered two transition methods for companies that did not use a year-end measurement date to transition to a December 31, 2008, measurement date. Mirant elected to use the alternative transition method under SFAS 158 for changing its measurement date, which resulted in an increase to the accumulated deficit of $2 million and accumulated other comprehensive income (loss) of $1 million as of January 1, 2008. Effective December 31, 2008, Mirant transitioned to a year-end measurement date for the funded status of its plans.

Table of Contents

The following table shows the projected benefit obligations and funded status for the defined benefit pension and other postretirement benefit plans of Mirant s continuing operations (in millions):

	Tax Qualified Pension Plans		Non-Tax Qualified Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007	2008	2007
Change in benefit obligation:						
Benefit obligation, beginning of year	$ 243	$ 244	$ 9	$ 9	$ 57	$ 107
Service cost	10	8			2	1
Interest cost	18	14			4	4
Amendments						(9)
Benefits paid	(11)	(8)			(3)	(2)
Curtailments	(1)				(2)	(32)
Actuarial (gain) loss	27	(15)			4	(12)
Benefit obligation, end of year	$ 286	$ 243	$ 9	$ 9	$ 62	$ 57
Change in plan assets:						
Fair value of plan assets, beginning of year	$ 205	$ 151	$	$	$	$
Return on plan assets	(52)	21				
Employer contributions	64	41			3	2
Benefits paid	(11)	(8)			(3)	(2)
Fair value of plan assets, end of year	$ 206	$ 205	$	$	$	$
Funded Status:						
Underfunded at measurement date	$ (80)	$ (38)	$ (9)	$ (9)	$ (62)	$ (57)

The accumulated benefit obligation exceeded the fair value of plan assets at December 31, 2008 and 2007, for the tax qualified pension plans. The total accumulated benefit obligation as of December 31, 2008, was $260 million. The total accumulated benefit obligation as of September 30, 2007, was $213 million.

The discount rates used as of December 31, 2008 and September 30, 2007, were determined based on individual bond-matching models comprised of portfolios of high quality corporate bonds with projected cash flows and maturity dates reflecting the expected time horizon during which that benefit will be paid. Bonds included in the model portfolios are from a cross-section of different issuers, are AA-rated or better, and are non-callable so that the yield to maturity can actually be attained without intervening calls.

The weighted average assumptions used for measuring year-end pension and other postretirement benefit plan obligations as of their respective measurement dates were as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Discount rate	5.40%	6.12%	5.37%	6.06%
Rate of compensation increases	3.37%	3.64%	3.00%	3.00%

Mirant assumed healthcare cost trend rates used for measuring year-end other postretirement benefit plan obligations as of their respective measurement dates were as follows:

	2008	2007
Assumed medical inflation for next year:		
Before age 65	8.50%	8.00%
Age 65 and after	8.50%	9.50%
Assumed ultimate medical inflation rate	5.00%	5.00%
Year in which ultimate rate is reached	2018	2015

Table of Contents

An annual increase or decrease in the assumed medical care cost trend rate of 1% would correspondingly increase or decrease the total accumulated benefit obligation of other postretirement benefit plans at December 31, 2008, by an inconsequential amount.

Amounts recognized in the consolidated balance sheets for pensions and other postretirement benefit plan obligations are shown below at December 31, 2008 and 2007 (in millions):

	Tax-Qualified Pension Plans		Non-Tax Qualified Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007	2008	2007
Current liabilities	$	$	$ (1)	$	$ (2)	$ (3)
Noncurrent liabilities	(80)	(38)	(8)	(9)	(60)	(54)
Total liability	$ (80)	$ (38)	$ (9)	$ (9)	$ (62)	$ (57)

Amounts recognized in accumulated other comprehensive income at December 31, 2008 and 2007, for pensions and other postretirement benefit plan obligations are as follows (in millions):

	Tax-Qualified Pension Plans		Non- Tax Qualified Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007	2008	2007
Net gain (loss)	$ (93)	$ 7	$ (2)	$ (1)	$ (16)	$ (15)
Prior service credit (cost)	(2)	(3)	(2)	(2)	26	38
Total amounts included in accumulated other comprehensive income (loss)	$ (95)	$ 4	$ (4)	$ (3)	$ 10	$ 23

Expected amortization payments. The estimated net gain (loss) and prior service credit (cost) for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2009 are $(1.3) million and $(0.5) million, respectively. Additionally, as of January 1, 2008, Mirant recognized $0 and $(0.1) million of net gain (loss) and prior service cost, respectively, to accumulated other comprehensive income for defined benefit pension plans as part of the transition adjustment related to the change in measurement date under SFAS 158.

The estimated net gain (loss) and prior service credit (cost) for other postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $(0.8) million and $5.8 million, respectively. Additionally, as of January 1, 2008, Mirant recognized $(0.2) million of net loss and $1.7 million of prior service credit to accumulated other comprehensive income for other postretirement benefit plans as part of the transition adjustment related to the change in measurement date under SFAS 158.

Table of Contents

The components of the net periodic benefit cost (credit) of Mirant s continuing operations pension and other postretirement benefit plans for the years ended December 31, 2008, 2007 and 2006, are shown below (in millions):

	Pension Plans Years Ended December 31,			Other Postretirement Benefit Plans Years Ended December 31,		
	2008	2007	2006	2008	2007	2006
Service cost	$ 8	$ 9	$ 10	$ 1	$ 2	$ 4
Interest cost	15	14	14	3	4	7
Expected return of plan assets	(17)	(13)	(10)			
Net amortization[1]	1	1	2	(5)	(3)	(1)
Curtailments	(1)			(4)	(32)	
Net periodic benefit cost (credit)	$ 6	$ 11	$ 16	$ (5)	$ (29)	$ 10

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

Other changes in plan assets and benefit obligation recognized in other comprehensive income for Mirant s continuing operations pension and other postretirement benefit plans (excluding $6 million for the year ended December 31, 2007 related to plans disposed of in 2007 as part of the various asset sales) for the years ended December 31, 2008 and 2007, were as follows (in millions):

	Pension Plans December 31,		Other Postretirement Benefit Plans December 31,	
	2008	2007	2008	2007
Net loss (gain)	$ 100	$ (24)	$ 1	$ (12)
Prior service cost (credit)		(1)		(9)
Amortization of:				
Net loss			(1)	(15)
Prior service cost (credit)	(1)		12	19
Total loss (income) recognized in other comprehensive income	$ 99	$ (25)	$ 12	$ (17)

The resulting total amount recognized in net periodic benefit cost and other comprehensive income for the pension plans for the years ended December 31, 2008 and 2007, was $105 million and $(14) million, respectively. The resulting total amount recognized in net periodic benefit cost and other comprehensive income for the other postretirement benefit plans for the years ended December 31, 2008 and 2007, was $7 million and $(46) million, respectively.

The weighted average assumptions used for Mirant s pension benefit cost and other postretirement benefit costs during each year were as follows:

	Pension Plans Years Ended December 31,			Other Postretirement Benefit Plans Years Ended December 31,		
	2008	2007	2006	2008	2007	2006
Discount rate	6.12%	5.66%	5.36%	6.06%	5.66%	5.36%
Rate of compensation increases	3.64%	3.70%	3.82%	3.00%	3.00%	3.00%
Expected long-term rate of return on plan assets	8.50%	8.50%	8.50%	%	%	%

Table of Contents

Mirant s assumed health care cost trend rates used to measure the expected cost of benefits covered by its other postretirement plan were as follows:

	2008	2007	2006
Assumed medical inflation for next year:			
Before age 65	8.00%	9.00%	10.00%
Age 65 and after	9.50%	11.00%	12.50%
Assumed ultimate medical inflation rate	5.00%	5.00%	5.00%
Year in which ultimate rate is reached	2015	2011	2011

An annual increase or decrease in the assumed medical care cost trend rate of 1% would correspondingly increase or decrease the aggregate of the service and interest cost components of the annual other postretirement benefit cost in 2008 by an inconsequential amount.

In determining the long-term rate of return for plan assets, the Company evaluates historic and current market factors such as inflation and interest rates before determining long-term capital market assumptions. The Company also considers the effects of diversification and portfolio rebalancing. To check for reasonableness and appropriateness, the Company reviews data about other companies, including their historic returns.

For purposes of expense recognition, the Company uses a market-related value of assets that recognizes the difference between the expected return and the actual return on plan assets over a five-year period. Unrecognized asset gains or losses associated with its plan assets, will be recognized in the calculation of the market-related value of assets and subject to amortization in future periods.

The following table shows the target allocation and percentage of fair value of plan assets by asset category for Mirant s qualified pension plans as of December 31, 2008 and 2007:

	Target Allocation	Percent of Fair Value of Plan Assets at December 31, 2008	2007
U.S. Stocks	50%	34%	55%
Non-U.S. Stocks	20	13	15
Fixed income	30	28	30
Cash		25	
Total	100%	100%	100%

For the qualified pension plans, Mirant uses a mix of equities and fixed income investments with the objective of maximizing the long-term return of pension plan assets at a prudent level of risk. The Company s risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. Equity investments are diversified across U.S. and non-U.S. stocks. For U.S. stocks, Mirant employs both a passive and active approach by investing in an index that mirrors the Russell 1000 Index and an actively managed small cap fund. For non-U.S. stocks, Mirant is invested in both developed and emerging market international equity funds that are benchmarked against the Europe, Australia and Far East Index. Fixed income investments are in a long U.S. government/credit index fund. Investment risk is monitored on an ongoing basis through quarterly portfolio reviews and annual pension liability measurements.

Primarily as a result of declines in the overall market of equity securities during 2008, the fair value of Mirant s pension plan assets declined considerably in 2008. As a result, the Company contributed $60 million to its pension plans in December of 2008 and a total of $64 million for the year ended December 31, 2008. Approximately $51 million of the $60 million the Company contributed in the fourth quarter of 2008 is included in the cash amount in the table above at December 31, 2008. This amount will be invested according to the Company s target allocation in 2009.

Mirant currently expects to contribute approximately $23 million to the tax-qualified pensions for the 2009 plan year. Of this amount, approximately $8 million is expected to be contributed during 2009 with the remainder contributed in 2010 based on the 2009 plan valuations. In addition, the Company expects to contribute approximately $1 million to the non-tax-qualified pension plans during 2009.

Mirant expects the following benefits to be paid from the pension and other postretirement benefit plans (in millions):

Projected Benefit Payments to Plan Participants	Pension Plans		Other Postretirement Benefits Plans	
	Tax-Qualified	Non-Tax Qualified	Before Medicare Subsidy	Medicare Subsidy
2009	$ 9.1	$ 0.8	$ 2.5	$
2010	9.8	0.9	2.5	
2011	10.3	0.9	2.1	
2012	11.3	0.9	2.5	
2013	12.6	0.9	2.9	0.1
2014 through 2018	86.1	4.8	20.8	0.8

Employee Savings and Profit Sharing Plan

The Company maintains a defined contribution employee savings plan with a profit sharing arrangement whereby employees may contribute a portion of their base compensation to the employee savings plan, subject to limits under the Internal Revenue Code. The Company provides a matching contribution each payroll period equal to 75% of the employee s contributions up to 6% of the employee s pay for that period. For unionized employees, matching levels vary by bargaining unit.

Under the profit sharing arrangement, the Company contributes a quarterly fixed contribution of 3% of eligible pay and may make an annual discretionary contribution for non-union employees not accruing a benefit under the defined benefit pension plan. Certain unionized employees are also eligible for the annual discretionary profit sharing contribution.

Expenses recognized for the matching, fixed profit sharing and discretionary profit sharing contributions were as follows (in millions):

	Matching	Fixed Profit Sharing	Discretionary Profit Sharing
2008	$ 5	$ 2	$ 2
2007	5	2	2
2006	5	2	1

Stock-based Compensation

The Mirant Corporation 2005 Omnibus Incentive Plan for certain employees and directors of Mirant became effective on January 3, 2006. The Omnibus Incentive Plan provides for the granting of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards, other stock-based awards, covered employee annual incentive awards and non-employee director awards. Under the Omnibus Incentive Plan, 18,575,851 shares of Mirant common stock are available for issuance to participants. Shares covered by an award are counted as used only to the extent that they are actually issued. Any shares related to awards that terminate by expiration, forfeiture, cancellation or otherwise without the issuance of such shares will be available again for grant under the Omnibus Incentive Plan. The Company utilizes both service condition and performance condition forms of stock-based compensation.

On October 5, 2006, the Compensation Committee of the Board of Directors approved the implementation of a special bonus plan to reward participants for successful completion of the Company s planned business and asset sales as well as to provide certain participants with an incentive to remain with the Company. The grants consisted of cash and restricted stock units. On November 13, 2006, the Company s Compensation Committee, pursuant to the Company s 2005 Omnibus Incentive Plan, awarded certain equity grants to five executive management members. The grants consisted of options to acquire the Company s common stock and restricted stock units. These grants were considered performance condition awards, as the payout under the November 13, 2006, awards was based on achieving certain target amounts related to the sales of the Company s Philippine and Caribbean businesses and six natural gas-fired facilities in the United States. The performance conditions were met at December 31, 2007, and the awards became fully vested and non-forfeitable on June 30, 2008.

SFAS 123R was adopted by the Company during the first quarter of 2006, using the modified prospective transition method. The Company recognizes compensation expense related to service condition and performance condition stock-based compensation. Compensation expense for the years ended December 31, 2008, 2007 and 2006 was as follows (in millions):

	Years Ended December 31,		
	2008	2007	2006
Service condition stock-based compensation	$ 21	$ 21	$ 16
Performance condition stock-based compensation	5	8	1
Total compensation expense	$ 26	$ 29	$ 17

The amounts in the table above are included in operations and maintenance expense in the consolidated statements of operations, with the exception of approximately $4 million for the year ended December 31, 2007, which is included in income from discontinued operations, net. As of December 31, 2008, there was approximately $22 million of total unrecognized compensation cost, excluding estimated forfeitures, related to non-vested share-based compensation granted through service condition awards, which is expected to be recognized on a straight-line basis over a weighted average period of approximately 1.4 years.

Stock Options

The fair value of stock options is estimated on the date of grant using a Black-Scholes option-pricing model based on the assumptions noted in the following table. As a result of the Company s bankruptcy and other factors, historical information concerning the Company s stock price volatility for purposes of valuing stock option grants is not sufficient. Therefore, the implied volatility derived from peer group companies was used as the basis for valuing the stock options granted through September 30, 2006. Beginning in the fourth quarter of 2006, the Company re-evaluated the use of implied volatility derived from peer group companies and determined that sufficient evidence existed to place exclusive reliance on Mirant s own implied volatility of its traded options in accordance with SAB 107. As a result of the lack of exercise history for the Company, the simplified method for estimating expected term has been used in accordance with SAB 107 and SAB 110, to the extent applicable. For performance condition awards, the Company utilized the contractual term as the expected term. The risk-free rate for periods within the contractual term of the stock option is based on the U.S. Treasury yield curve in effect at the time of the grant. The table below includes significant assumptions used in valuing the Company s stock options:

	Years Ended December 31,					
	2008		2007		2006	
	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average
Expected volatility	31 - 43%	31.2%	15 - 28%	19.9%	21 - 37%	31.6%
Expected dividends	%	%	%	%	%	%
Expected term						
Service condition awards	3.5 years	3.5 years	2.7 - 3.5 years	3.48 years	5.2 - 6 years	5.9 years
Performance condition awards					3 years	3 years
Risk-free rate	2.1 - 2.9%	2.1%	4 - 4.7%	4%	4.3 - 5.1%	4.5%

Table of Contents

Service Condition Awards

During 2006, Mirant made awards of nonqualified stock options to purchase approximately 3 million shares. These stock options were granted with a 10-year term. Options to purchase approximately 1.8 million shares vest 25% six months from the grant date and 25% on each of the first, second and third anniversaries of the grant date. Options to purchase approximately 1.1 million shares vest in three equal installments on each of the first, second and third anniversaries of the grant date. Options to purchase approximately 41,000 shares were granted to non-management members of the Board of Directors and vest one year from the grant date.

During 2007, the Company granted options to purchase a total of approximately 605,000 shares. These stock options were granted with a five-year term, and vest in three equal installments on each of the first, second and third anniversaries of the grant date. Options to purchase approximately 15,000 shares were granted to non-management members of the Board of Directors and vest one year from the grant date.

During 2008, the Company granted options to purchase a total of approximately 752,000 shares. These stock options were granted with a five-year term, and vest in three equal installments on each of the first, second and third anniversaries of the grant date. There were no stock options granted to non-management members of the Board of Directors during 2008.

The granted options provide for accelerated vesting if there is a change of control (as defined in the Omnibus Incentive Plan) or, in certain circumstances, as a result of a termination of employment. Options to purchase approximately 808,000, 1.1 million and 525,000 shares vested during 2008, 2007 and 2006, respectively, of which approximately 37,000, 177,000 and 87,000 shares for 2008, 2007 and 2006, respectively, became exercisable as a result of accelerated vesting resulting from the termination of an employee. The weighted average grant-date fair value of stock options granted during the years ended December 31, 2008, 2007 and 2006, was $9.49, $8.44 and $10.42 per share, respectively.

A summary of the Company s option activity under the Omnibus Incentive Plan is presented below:

Stock Options	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2006		$		$
Granted	2,987,936	$ 24.89		
Exercised or converted	(23,287)	$ 25.05		$
Forfeited	(162,930)	$ 24.96		
Expired		$		
Outstanding at December 31, 2006	2,801,719	$ 24.89	9.2	$ 18,720
Granted	605,386	$ 37.91		
Exercised or converted	(371,306)	$ 25.98		$
Forfeited	(131,755)	$ 29.64		
Expired		$		
Outstanding at December 31, 2007	2,904,044	$ 27.25	7.4	$ 34,069
Granted	751,511	$ 36.87		
Exercised or converted	(659,804)	$ 25.63		$
Forfeited	(69,540)	$ 36.12		
Expired	(55,215)	$ 31.95		
Outstanding at December 31, 2008	2,870,996	$ 29.83	5.8	$
Exercisable or convertible at December 31, 2008	1,244,568	$ 26.44	6.7	$

F-36

Table of Contents

The range of exercise prices for stock options granted is presented below:

	High	Low
2008	$ 37.02	$ 26.20
2007	$ 45.77	$ 37.71
2006	$ 28.89	$ 23.70

Cash received from the exercise of stock options under the Omnibus Incentive Plan for the years ended December 31, 2008, 2007 and 2006, was approximately $17 million, $10 million and $583,000, respectively, and no related tax benefit was recognized during the years then ended.

Performance Condition Awards

On November 13, 2006, Mirant made awards of nonqualified stock options to purchase approximately 830,000 shares to five members of executive management. These options were granted with a three-year term and vested on June 30, 2008, as the Company achieved the required performance target amounts by December 31, 2007. The options provided for accelerated vesting if there was a change of control (as defined in the Omnibus Incentive Plan) or, in certain circumstances, as a result of a termination of employment. At December 31, 2007, options to purchase approximately 100,000 shares became exercisable as a result of accelerated vesting resulting from the termination of an employee. The weighted average grant date fair value of performance condition stock options granted during the year ended December 31, 2006, was $6.08 per share. There were no performance condition stock options granted during 2008 or 2007.

A summary of option activity for performance condition awards under the Omnibus Incentive Plan is presented below:

Stock Options	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2006		$		$
Granted	830,000	$ 28.89		
Exercised or converted		$		
Forfeited		$		
Expired		$		
Outstanding at December 31, 2006	830,000	$ 28.89	2.9	$ 2,224
Granted		$		
Exercised or converted		$		
Forfeited		$		
Expired		$		
Outstanding at December 31, 2007	830,000	$ 28.89	1.9	$ 8,375
Granted		$		
Exercised or converted	(44,507)	$ 28.89		$
Forfeited		$		
Expired	(55,493)	$ 28.89		
Outstanding at December 31, 2008	730,000	$ 28.89	.9	$
Exercisable or convertible at December 31, 2008	730,000	$ 28.89	.9	$

Table of Contents

Restricted Stock Shares and Restricted Stock Units

Service Condition Awards

During 2006, the Company issued approximately 392,000 restricted stock units and 205,000 restricted stock shares under the Omnibus Incentive Plan. Approximately 350,000 restricted stock units vest 25% six months from the grant date, and 25% on each of the first, second and third anniversaries of the grant date. Approximately 34,000 of the restricted stock units and 205,000 of the restricted stock shares vest in three equal installments on each of the first, second and third anniversaries of the grant date. Approximately 8,000 of the restricted stock units were granted to non-management members of the Board of Directors and vest one year from the grant date. The granted restricted stock units and restricted stock shares provide for accelerated vesting if there is a change of control (as defined in the Omnibus Incentive Plan) or, in certain circumstances, as a result of a termination of employment.

During 2007, the Company issued approximately 428,000 restricted stock units under the Omnibus Incentive Plan. Approximately 419,000 of the restricted stock units vest on each of the first, second and third anniversaries of the grant date. Approximately 9,000 of the restricted stock units were granted to non-management members of the Board of Directors and vest one year from the grant date. The granted restricted stock units and restricted stock shares provide for accelerated vesting if there is a change of control (as defined in the Omnibus Incentive Plan) or, in certain circumstances, as a result of a termination of employment.

During 2008, the Company issued approximately 403,000 of restricted stock units under the Omnibus Incentive Plan. Approximately 388,000 of the restricted stock units vest on each of the first, second and third anniversaries of the grant date. Approximately 15,000 of the restricted stock units were granted to non-management members of the Board of Directors and vest one year from the grant date. The granted restricted stock units and restricted stock shares provide for accelerated vesting if there is a change of control (as defined in the Omnibus Incentive Plan) or, in certain circumstances, as a result of a termination of employment.

Approximately 269,000, 213,000 and 105,000 restricted stock units vested during the years ended December 31, 2008, 2007 and 2006, respectively, of which, approximately 13,000, 54,000 and 17,000, respectively, became fully vested as a result of the termination of employees.

The grant date fair value of the restricted stock shares and restricted stock units is equal to the Company s closing stock price on the grant date. As restricted stock shares and restricted stock units vest, the outstanding balance of restricted stock shares and restricted stock units decreases and the number of outstanding shares of common stock increases by an equal amount. A summary of the Company s restricted stock shares and restricted stock units for service condition award is presented below:

Restricted Stock Shares and Restricted Stock Units	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2006		$
Granted	597,596	$ 24.89
Vested	(104,991)	$ 24.84
Forfeited	(32,586)	$ 24.96
Outstanding at December 31, 2006	460,019	$ 24.90
Granted	428,035	$ 37.89
Vested	(212,700)	$ 26.65
Forfeited	(45,381)	$ 33.16
Outstanding at December 31, 2007	629,973	$ 32.54
Granted	403,300	$ 36.90
Vested	(269,337)	$ 31.63
Forfeited	(68,117)	$ 37.01
Outstanding at December 31, 2008	695,819	$ 34.98

Table of Contents

Performance Condition Awards

During 2006, the Company issued 283,554 restricted stock units under the Omnibus Incentive Plan. Approximately 140,000 were awarded on October 31, 2006 to certain key employees and approximately 143,000 on November 13, 2006, to five members of executive management. The restricted stock units vested on June 30, 2008, based on the Company achieving the performance target amounts by December 31, 2007. The granted restricted stock units provided for accelerated vesting if there is a change of control (as defined in the Omnibus Incentive Plan) or, in certain circumstances, as a result of a termination of employment. Approximately 3,000 and 37,000 restricted stock units and shares vested during the year ended December 31, 2008 and 2007, as a result of the termination of employees. The grant date fair value of the restricted stock and restricted stock units for performance condition awards is equal to the Company s closing stock price on the grant date.

A summary of the Company s restricted stock units awarded is as follows:

Restricted Stock Units	**Number of Shares**	**Weighted Average Grant Date Fair Value**
Outstanding at December 31, 2006		$
Granted	283,554	$ 29.23
Vested		$
Forfeited		$
Outstanding at December 31, 2006	283,554	$ 29.23
Granted		$
Vested	(36,564)	$ 29.25
Forfeited		$
Outstanding at the December 31, 2007	246,990	$ 29.22
Granted		$
Vested	(246,990)	$ 29.22
Forfeited		$
Outstanding at December 31, 2008		$

9. Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS 143, which requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Additionally, effective December 31, 2005, the Company adopted FIN 47, which expands the scope of asset retirement obligations to be recognized to include asset retirement obligations that may be uncertain as to the nature or timing of settlement. Upon initial recognition of a liability for an asset retirement obligation or a conditional asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 and FIN 47 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company identified certain asset retirement obligations within its power generating facilities. These asset retirement obligations are primarily related to asbestos abatement in facilities on owned or leased property and other environmental obligations related to fuel storage facilities, wastewater treatment facilities, ash disposal sites and pipelines.

Asbestos abatement is the most significant type of asset retirement obligation identified for recognition in connection with the Company s adoption of FIN 47. The EPA has regulations in place governing the removal of

Table of Contents

asbestos. Because of the nature of asbestos, it can be difficult to ascertain the extent of contamination in older facilities unless substantial renovation or demolition takes place. Therefore, the Company incorporated certain assumptions based on the relative age and size of its facilities to estimate the current cost for asbestos abatement. The actual abatement cost could differ from the estimates used to measure the asset retirement obligation. As a result, these amounts will be subject to revision when actual abatement activities are undertaken. In the third quarter of 2008, the Company increased its current cost estimates for asset retirement obligations associated with asbestos abatement at its generating facilities as a result of the cost of the asbestos abatement at the Lovett facility. The increase in the current cost estimates resulted in an increase to the asset retirement obligations of approximately $2 million.

The following table sets forth the balances of the asset retirement obligations as of January 1, 2007, and the additions and accretion of the asset retirement obligations for the years ended December 31, 2008 and 2007. The asset retirement obligations are included in noncurrent liabilities in the consolidated balance sheets (in millions):

	For the Years Ended December 31,	
	2008	2007
Beginning balance January 1	$ 44	$ 40
Liabilities recorded in the period	2	3
Liabilities settled during the period	(9)	(2)
Accretion expense	3	3
Ending balance, December 31	$ 40	$ 44

10. Commitments and Contingencies

Mirant has made firm commitments to buy materials and services in connection with its ongoing operations and has made financial guarantees relative to some of its investments.

Cash Collateral

In order to sell power and purchase fuel in the forward markets and perform other energy trading and marketing activities, the Company often is required to provide trade credit support to its counterparties or make deposits with brokers. In addition, the Company often is required to provide cash collateral for access to the transmission grid to participate in power pools and for other operating activities. In the event of default by the Company, the counterparty can apply cash collateral held to satisfy the existing amounts outstanding under an open contract.

The following is a summary of cash collateral posted with counterparties as of December 31, 2008 and 2007 (in millions):

	At December 31,	
	2008	2007
Cash collateral posted energy trading and marketing	$ 67	$ 96
Cash collateral posted other operating activities	44	14
Total	$ 111	$ 110

Table of Contents

Commitments

In addition to debt and other obligations in the consolidated balance sheets, Mirant has the following annual commitments under various agreements at December 31, 2008, related to its operations (in millions):

		Off-Balance Sheet Arrangements and Contractual Obligations by Year					
	Total	2009	2010	2011	2012	2013	>5 Years
Mirant Mid-Atlantic operating leases	$ 2,013	$ 142	$ 140	$ 134	$ 132	$ 138	$ 1,327
Other operating leases	57	9	9	7	5	6	21
Fuel commitments	1,254	374	335	314	196	35	
Maryland Healthy Air Act	677	490	187				
Other	336	186	41	32	22	15	40
Total payments	$ 4,337	$ 1,201	$ 712	$ 487	$ 355	$ 194	$ 1,388

The Company s contractual obligations table does not include the derivative obligations which are discussed in Note 4 and the asset retirement obligations which are discussed in Note 9.

Operating Leases

Mirant Mid-Atlantic leases the Dickerson and Morgantown baseload units and associated property through 2029 and 2034, respectively. Mirant Mid-Atlantic has an option to extend the leases. Any extensions of the respective leases would be for less than 75% of the economic useful life of the facility, as measured from the beginning of the original lease term through the end of the proposed remaining lease term. The Company is accounting for these leases as operating leases and recognizes rent expense on a straight-line basis. Rent expense totaled $96 million for the years ended December 31, 2008, 2007 and 2006, and is included in operations and maintenance expense in the accompanying consolidated statements of operations. As of December 31, 2008 and 2007, the Company has paid approximately $354 million and $330 million, respectively, of lease payments in excess of rent expense recognized, which is recorded in prepaid rent and prepaid expenses on the consolidated balance sheets. Of these amounts, $96 million is included in prepaid expenses on the Company s consolidated balance sheets as of December 31, 2008 and 2007.

As of December 31, 2008, the total notional minimum lease payments for the remaining terms of the leases aggregated approximately $2.0 billion and the aggregate termination value for the leases was approximately $1.4 billion, which generally decreases over time. Mirant Mid-Atlantic leases the Dickerson and the Morgantown baseload units from third party owner lessors. These owner lessors each own the undivided interests in these baseload generating facilities. The subsidiaries of the institutional investors who hold the membership interests in the owner lessors are called owner participants. Equity funding by the owner participants plus transaction expenses paid by the owner participants totaled $299 million. The issuance and sale of pass through certificates raised the remaining $1.2 billion needed for the owner lessors to acquire the undivided interests.

The pass through certificates are not direct obligations of Mirant Mid-Atlantic. Each pass through certificate represents a fractional undivided interest in one of three pass through trusts formed pursuant to three separate pass through trust agreements between Mirant Mid-Atlantic and U.S. Bank National Association (as successor in interest to State Street Bank and Trust Company of Connecticut, National Association), as pass through trustee. The property of the pass through trusts consists of lessor notes. The lessor notes issued by an owner lessor are secured by that owner lessor s undivided interest in the lease facilities and its rights under the related lease and other financing documents.

Mirant has commitments under other operating leases with various terms and expiration dates.

Fuel Commitments

Fuel commitments primarily relate to long-term coal agreements and related transportation agreements.

Maryland Healthy Air Act

Maryland Healthy Air Act commitments reflect the remaining capital expenditures that the Company expects to incur to comply with the limitations for SO2, NOx and mercury emissions under the Maryland Healthy Air Act.

Other

Other represents the open purchase orders less invoices received related to open purchase orders for procurement of products and services purchased in the ordinary course of business. These include construction, maintenance and labor activities at the Company s generating facilities. Other also includes the Company s LTSA associated with the maintenance of turbines at the Kendall facility, limestone supply and transportation agreements, estimated pension and other postretirement benefit funding obligations, deferred compensation plans, FIN 48 liabilities and miscellaneous long-term liabilities, which are included in other noncurrent liabilities on the consolidated balance sheet.

Guarantees

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 expressed guarantees or 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, commodity purchase and sale agreements, 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.

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 under FIN 45. Generally, guarantees of the performance of a third party are subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation. The Company did not have any guarantees at December 31, 2008, that met the recognition requirements under FIN 45.

Alternatively, guarantees between and on behalf of entities under common control are subject only to the disclosure provisions of FIN 45. The Company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

Letters of Credit and Surety Bonds

As of December 31, 2008, Mirant and its subsidiaries were contingently obligated for $301 million under letters of credit issued under the credit facilities of Mirant North America, which includes $122 million of letters of credit issued pursuant to its senior secured term loan and $172 million of letters of credit issued pursuant to its revolving credit facility. Most of these letters of credit are issued in support of the obligations of Mirant North America and its subsidiaries to perform under commodity agreements, financing or lease agreements or other commercial arrangements. In the event of default by the Company, the counterparty can draw on a letter of credit to satisfy the existing amounts outstanding under an open contract. A majority of these letters of credit expire within one year of issuance, and it is typical for them to be renewed on similar terms. In addition, the Company has entered into a cash-collateralized letter of credit facility pursuant to which it posted letters of credit in support of the Company s response to a request for proposals for new power generation.

The Company has obligations under surety bonds that were posted as credit support for the RGGI auction that was held in December 2008. These surety bonds expire within one year, and it is typical for them to be renewed on similar terms. As of December 31, 2008, Mirant and its subsidiaries posted a $25 million surety bond as credit support for the RGGI auction.

Following is a summary of letters of credit issued and surety bonds as of December 31, 2008 and 2007 (in millions):

	At December 31,	
	2008	2007
Letters of credit energy trading and marketing	$ 76	$ 100
Letters of credit debt service and rent reserves	101	78
Letters of credit other operating activities	124	112
Surety bonds energy trading and marketing	25	
Total	$ 326	$ 290

Purchase and Sale Guarantees and Indemnifications

In connection with the purchase or sale of an asset or a business by Mirant through a subsidiary, Mirant is typically required to provide certain assurances to the counterparties for the performance of the obligations of such a subsidiary under the purchase or sale agreements. Such assurances may take the form of a guarantee issued by Mirant or a subsidiary on behalf of the obligor subsidiary. The scope of such guarantees would typically include any indemnity obligations owed to such counterparty. While the terms thereof vary in the scope, exclusions, thresholds and applicable limits, the indemnity obligations of a seller typically include liabilities incurred as a result of a breach of a purchase and sale agreement, including the indemnifying party s representations or warranties, unpaid and unreserved tax liabilities and specified retained liabilities, if any. These obligations generally have a term of 12 months from the closing date and are intended to protect the non-indemnifying parties against breaches of the agreement or risks that are difficult to predict or estimate at the time of the transaction. In most cases, the contract limits the liability of the indemnifying party. While the primary indemnity periods under the agreements for the sales of the Philippine and Caribbean businesses and six U.S. natural gas-fired facilities have elapsed without any claims being made, Mirant continues to have indefinite indemnity obligations in respect of certain representations and covenants that are typically not subject to lapse. No claims have been made in respect thereof and the Company does not expect that it will be required to make any material payments under these guarantee and indemnity provisions.

Commercial Purchase and Sales Arrangements

In connection with the purchase and sale of fuel, emissions allowances and energy to and from third parties with respect to the operation of Mirant s generating facilities, the Company may be required to guarantee a portion of the obligations of certain of its subsidiaries. These obligations may include liquidated damages payments or other unscheduled payments. The majority of the current guarantees are set to expire before the end of 2010, although the obligations of the issuer will remain in effect until all the liabilities created under the guarantee have been satisfied or no longer exist. As of December 31, 2008, Mirant and its subsidiaries were contingently obligated for a total of $101 million under such arrangements. The Company does not expect that it will be required to make any material payments under these guarantees.

Other Guarantees and Indemnifications

As of December 31, 2008, Mirant has issued $67 million of guarantees of obligations that its subsidiaries may incur in connection with construction agreements, equipment leases and on-going litigation. The Company does not expect that it will be required to make any material payments under these guarantees.

The Company, through its subsidiaries, participates in several power pools with RTOs. The rules of these RTOs require that each participant indemnify the pool for defaults by other members. Usually, the amount indemnified is based upon the activity of the participant relative to the total activity of the pool and the amount of the default. Consequently, the amount of such indemnification by the Company cannot be quantified.

On a routine basis in the ordinary course of business, Mirant and its subsidiaries indemnify financing parties and consultants or other vendors who provide services to the Company. The Company does not expect that it will be required to make any material payments under these indemnity provisions.

Because some of the guarantees and indemnities Mirant issues to third parties do not limit the amount or duration of its obligations to perform under them, there exists a risk that the Company may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit the Company s liability exposure, the Company may not be able to estimate its potential liability until a claim is made for payment or performance, because of the contingent nature of these contracts.

11. Dispositions

Overview

The Company had no assets or liabilities held for sale at December 31, 2008 or 2007. The Company disposed of certain discontinued operations and other assets in 2007. In the third quarter of 2006, Mirant commenced separate auction processes to sell its Philippine (2,203 MW) and Caribbean (1,050 MW) businesses and six U.S. natural gas-fired facilities totaling 3,619 MW, consisting of the Zeeland (903 MW), West Georgia (613 MW), Shady Hills (469 MW), Sugar Creek (561 MW), Bosque (546 MW) and Apex (527 MW) facilities.

The sale of the six U.S. natural gas-fired facilities was completed on May 1, 2007. In the third quarter of 2006, the Company recorded an impairment loss of $396 million to reduce the carrying value of the six facilities held for sale to estimated fair value. In subsequent periods, the Company recorded reductions to the impairment loss of approximately $51 million resulting from the sale process. As a result, the Company recognized a cumulative loss of $345 million related to the sale of the six facilities. The net proceeds to Mirant after transaction costs and retiring $83 million of project-related debt were $1.306 billion.

The Company completed the sale of Mirant NY-Gen on May 7, 2007. The Company recognized a gain of $8 million related to the sale. The proceeds related to the sale were immaterial as a result of the transfer of the net liabilities of Mirant NY-Gen.

The sale of the Philippine business was completed on June 22, 2007. The Company recognized a gain of $2.003 billion related to the sale. The net proceeds to Mirant after transaction costs and the repayment of $642 million of debt were $3.21 billion.

The sale of the Caribbean business was completed on August 8, 2007. The Company recognized a gain of approximately $63 million in the third quarter of 2007 related to the sale. The net proceeds to Mirant after transaction costs and final working capital adjustments were $555 million.

During the second quarter of 2007, the Company recognized $9 million of other comprehensive income, net of tax, related to the sale of the Philippine business. Of this amount, $5 million was related to a pension liability that was settled as part of the sale and $4 million was related to a cumulative translation adjustment. During the third quarter of 2007, the Company recognized $11 million of other comprehensive loss, net of tax, related to pension and other postretirement benefits as part of the sale of the Caribbean business.

Discontinued Operations

The Company has reclassified amounts for prior periods in the financial statements to report separately, as discontinued operations, the revenues and expenses of components of the Company that have been disposed of as of December 31, 2008.

The Company sold its Wrightsville power generating facility in 2005, but retained transmission credits that arose from transmission system upgrades associated with the construction of the Wrightsville facility. During the third quarter of 2007, Mirant entered into an agreement that established the amount of the outstanding transmission credits. As a result of the agreement, Mirant recognized a gain of $24 million in income from discontinued operations in the third quarter of 2007.

For the year ended December 31, 2007, income from discontinued operations included the results of operations of the Caribbean business, the Philippine business, the six U.S. natural gas-fired facilities and Mirant NY-Gen through their respective dates of sale and the gain related to Wrightsville described above. For the year ended December 31, 2006, income from discontinued operations included the results of operations of all the discontinued businesses and assets for the entire year, as well as the Wichita Falls facility in Texas through its May 2006 date of sale.

As part of the sale of Mirant NY-Gen, Mirant retained the rights to future insurance recoveries related to repairs of the dam at the Swinging Bridge facility. In the fourth quarter of 2007, the Company reached an insurance settlement and recognized a gain of $10 million, which is included in income from discontinued operations.

A summary of the operating results for these discontinued operations for the years ended December 31, 2007 and 2006 is as follows (in millions):

	Year Ended December 31, 2007			
	U.S.	Philippines	Caribbean	Total
Operating revenues	$ 82	$ 200	$ 514	$ 796
Operating expenses (income):				
Gain on sales of assets	(38)	(2,003)	(63)	(2,104)
Other operating expenses	56	67	433	556
Total operating expenses (income)	18	(1,936)	370	(1,548)
Operating income	64	2,136	144	2,344
Provision (benefit) for income taxes		704	13	717
Other expense (income), net		33	32	65
Net income	$ 64	$ 1,399	$ 99	$ 1,562

	Year Ended December 31, 2006			
	U.S.	Philippines	Caribbean	Total
Operating revenues	$ 303	$ 469	$ 825	$ 1,597
Operating expenses:				
Loss on sales of assets	375			375
Other operating expenses	221	187	686	1,094
Total operating expenses	596	187	686	1,469
Operating income (loss)	(293)	282	139	128

Provision (benefit) for income taxes	1	(104)	26	(77)
Other expense (income), net	9	30	54	93
Net income (loss)	$ (303)	$ 356	$ 59	$ 112

On July 12, 2006, the Company s Sual generating facility in the Philippines had an unplanned outage of unit 2 as a result of a failure of the generator. The repairs on unit 2 were completed on March 4, 2007, and the unit returned to operation. On October 23, 2006, unit 1 at the Sual generating facility had an unplanned outage as a result of a failure of the generator. The repairs on unit 1 were completed on June 12, 2007, and the unit returned to operation.

As part of the sale of the Philippine business, Mirant retained the rights to future insurance recoveries related to outages of the Sual generating facility that occurred prior to the sale. In 2007, the Company received a total of $23 million related to these recoveries. In the second quarter of 2008, the Company entered into a settlement and received approximately $50 million in additional insurance recoveries. For the year ended December 31, 2008, income from discontinued operations includes a gain of $50 million related to this settlement. Of this amount, $41 million related to business interruption recoveries and is included in cost of fuel, electricity and other products and $9 million related to property insurance recoveries and is included in total operating expenses.

12. Bankruptcy Related Disclosures

Mirant s Plan was confirmed by the Bankruptcy Court on December 9, 2005, and the Company emerged from bankruptcy on January 3, 2006. For financial statement presentation purposes, Mirant recorded the effects of the Plan at December 31, 2005.

At December 31, 2008 and 2007, amounts related to allowed claims, estimated unresolved claims and professional fees associated with the bankruptcy that are to be settled in cash were $14 million and $27 million, respectively, and these amounts were recorded in accounts payable and accrued liabilities on the accompanying consolidated balance sheets. These amounts do not include unresolved claims that will be settled in common stock or the stock portion of claims that are expected to be settled with cash and stock. For the years ended December 31, 2008, 2007 and 2006, the Company paid approximately $16 million, $53 million and $814 million, respectively, in cash related to bankruptcy claims, which is reflected in cash flows from operating activities from continuing operations. In addition, for 2006, approximately $990 million is reflected in cash flows from financing activities from continuing operations and $45 million from discontinued operations and together represent the principal amount of debt claims. As of December 31, 2008, approximately 850,000 of the shares of Mirant common stock to be distributed under the Plan have not yet been distributed and have been reserved for distribution with respect to claims that are disputed by the Mirant Debtors and have yet to be resolved. See Note 16 for further discussion of the Chapter 11 proceedings.

Reorganization Items, net

Reorganization items, net represents expense, income and gain or loss amounts that were recorded in the financial statements as a result of the bankruptcy proceedings. In 2006, reorganization items, net relate to refunds received from various New York tax jurisdictions for the settlement of the property tax dispute related to the New York subsidiaries. Reorganization items, net for the years ended December 31, 2008, 2007 and 2006, are comprised of the following (in millions):

	Years Ended December 31,		
	2008	**2007**	**2006**
Gain on New York property tax settlement	$	$	$ (163)
Professional fees and administrative expense		3	2
Interest income, net		(5)	(3)
Total	$	$ (2)	$ (164)

F-46

13. Stockholders Equity and Earnings Per Share
Stockholders Equity

On January 3, 2006, all shares of Mirant s old common stock were cancelled and 300 million shares of Mirant s new common stock were issued. At December 31, 2008, approximately 850,000 shares of common stock are reserved for unresolved claims pursuant to Mirant s emergence from bankruptcy.

Mirant also issued two series of warrants that will expire on January 3, 2011. The Series A Warrants and Series B Warrants entitled the holders as of the date of issuance to purchase an aggregate of approximately 35 million and 18 million shares of New Mirant common stock, respectively. The exercise price and number of common shares issuable are subject to adjustments based on the occurrence of certain events, including (1) dividends or distributions, (2) rights offerings or (3) other distributions. Mirant s common stock is currently traded on the NYSE under the ticker symbol MIR. For the years ended December 31, 2008 and 2007, there were approximately 8.2 million and 0.2 million of Series A Warrants, respectively, and 10.1 million and 0.5 million of Series B Warrants, respectively, that were exercised. Substantially all of these exercises were made by net share settlement, resulting in the issuance of approximately 8.2 million and 0.4 million net shares of common stock for the years ended December 31, 2008 and 2007, respectively. At December 31, 2008, there were approximately 26.9 million Series A Warrants and 7.1 million Series B Warrants outstanding. The warrants are recorded as a component of additional paid-in capital in the accompanying consolidated balance sheets.

On January 3, 2006, the Omnibus Incentive Plan for certain employees and directors of Mirant became effective. Under the Omnibus Incentive Plan, 18,575,851 shares of Mirant common stock are available for issuance to participants. See Note 8 for further discussion of the Omnibus Incentive Plan.

Share Repurchases

During the third quarter of 2006, the Company repurchased 43 million shares of Mirant common stock for an aggregate purchase price of approximately $1.228 billion. On September 28, 2006, the Company announced that its Board of Directors had authorized a $100 million share repurchase program which expired in September 2007. As of September 30, 2007, the Company had repurchased 1.18 million shares under this program for an aggregate purchase price of approximately $32 million.

In January 2007, the Company began a program of repurchasing shares at market prices from stockholders holding less than 100 shares of Mirant stock. For the year ended December 31, 2007, the Company repurchased approximately 245,000 shares for approximately $9 million. The Company did not make any purchases under this program in 2008.

On November 9, 2007, Mirant announced that it planned to return a total of $4.6 billion of excess cash to its stockholders based on four factors: (1) the outlook for the business, (2) preserving the Company s credit profile, (3) maintaining adequate liquidity, including for capital expenditures and (4) maintaining sufficient working capital. On September 22, 2008, Mirant announced that it had returned $3.856 billion of cash to its stockholders and suspended its program to return excess cash to its stockholders based on its evaluation of the four factors that were set out upon commencement of the share repurchase program. On November 7, 2008, Mirant announced that it was resuming its program of returning excess cash to its stockholders and would purchase an additional $200 million of shares through open market purchases. This $200 million of purchases was completed in the fourth quarter of 2008 and was in addition to the previous $3.856 billion of cash returned to its stockholders. A detailed timeline of the program is as follows:

On November 9, 2007, Mirant announced that the first stage of the cash distribution would be accomplished through an accelerated share repurchase program for $1 billion, plus open market purchases for up to an additional $1 billion. In the fourth quarter of 2007, the Company repurchased 26.66 million shares of common stock for $1 billion through the accelerated share repurchase program.

Table of Contents

On February 29, 2008, the Company announced that it had decided to return the remaining $2.6 billion of cash through open market purchases of common stock but that it would continue to evaluate the most efficient method to return the cash to stockholders.

On May 15, 2008, the accelerated share repurchase program was completed and Mirant received an additional 682,387 shares, resulting in a total of 27.34 million shares purchased. The final price of shares repurchased under the accelerated share repurchase program was $36.57 per share, which was determined based on a discount to the volume weighted average trading price of Mirant s common stock over the period of the accelerated share repurchase program.

Between November 2007 and December 2008, Mirant returned approximately $4.056 billion of cash to its stockholders through purchases of 122 million shares of its common stock, including 86 million shares that were purchased through open market purchases in 2008 for approximately $2.74 billion. The Company has repurchased approximately 48% of the 256 million basic shares that it had outstanding when the program began in November 2007.

Earnings 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 shares and restricted stock units, stock options and warrants. The Company excluded 0.6 million, 0.5 million and 3.4 million of potential common shares representing antidilutive stock options from the earnings per share calculations for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table shows the computation of basic and diluted EPS for the years ended December 31, 2008, 2007 and 2006 (in millions except per share data):

	2008	2007	2006
Net income from continuing operations	$ 1,215	$ 433	$ 1,752
Net income from discontinued operations	50	1,562	112
Net income as reported	$ 1,265	$ 1,995	$ 1,864
Basic and diluted:			
Weighted average shares outstanding basic	186	252	285
Shares from assumed exercise of warrants and options	13	25	11
Shares from assumed vesting of restricted stock and restricted stock units			1
Weighted average shares outstanding diluted	199	277	297
Basic EPS			
EPS from continuing operations	$ 6.53	$ 1.72	$ 6.15
EPS from discontinued operations	0.27	6.20	0.39
Basic EPS	$ 6.80	$ 7.92	$ 6.54
Diluted EPS			
EPS from continuing operations	$ 6.11	$ 1.56	$ 5.90
EPS from discontinued operations	0.25	5.64	0.38
Diluted EPS	$ 6.36	$ 7.20	$ 6.28

Table of Contents

14. 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 5,230 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. Other Operations includes proprietary trading and fuel oil management activities. For the years ended December 31, 2007 and 2006, Other Operations also included gains and losses related to the Back-to-Back Agreement which was terminated pursuant to a settlement that became effective in the third quarter of 2007. See Note 17 for further discussion of the Back-to-Back Agreement. Other Operations also includes unallocated corporate overhead, interest 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)			
2008:						
Operating revenues[1]	$ 2,279	$ 617	$ 186	$ 102	$ 4	$ 3,188
Cost of fuel, electricity and other products[2]	565	438	59	(1)	(2)	1,059
Gross margin	1,714	179	127	103	6	2,129
Operating Expenses:						
Operations and maintenance	412	167	76	28		683
Depreciation and amortization	92	19	23	10		144
Loss (gain) on sales of assets, net	(8)	(30)	(7)	(2)	8	(39)
Total operating expenses	496	156	92	36	8	788
Operating income (loss)	1,218	23	35	67	(2)	1,341
Total other expense (income), net	1	(1)	1	123		124
Income (loss) from continuing operations before income taxes	1,217	24	34	(56)	(2)	1,217
Provision for income taxes				2		2
Income (loss) from continuing operations	$ 1,217	$ 24	$ 34	$ (58)	$ (2)	$ 1,215
Total assets	$ 5,620	$ 722	$ 181	$ 7,253	$ (3,088)	$ 10,688
Gross property additions	$ 641	$ 25	$ 6	$ 59	$	$ 731

(1) Includes unrealized gains of $685 million, $35 million and $120 million for Mid-Atlantic, Northeast and Other Operations, respectively.

(2) Includes unrealized losses of $9 million and $45 million for Mid-Atlantic and Northeast, respectively.

Table of Contents

Operating Segments

	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
			(in millions)			
2007:						
Operating revenues[1]	$ 1,133	$ 664	$ 177	$ 45	$	$ 2,019
Cost of fuel, electricity and other products[2]	528	427	42	(67)	(18)	912
Gross margin	605	237	135	112	18	1,107
Operating Expenses:						
Operations and maintenance	360	179	74	94		707
Depreciation and amortization	81	25	13	10		129
Impairment losses		175				175
Loss (gain) on sales of assets, net		(49)	(2)	(5)	11	(45)
Total operating expenses	441	330	85	99	11	966
Operating income (loss)	164	(93)	50	13	7	141
Total other income, net	(5)	(7)	(5)	(282)		(299)
Income (loss) from continuing operations before reorganization items and income taxes	169	(86)	55	295	7	440
Reorganization items, net		(2)				(2)
Provision for income taxes				9		9
Income (loss) from continuing operations	$ 169	$ (84)	$ 55	$ 286	$ 7	$ 433
Total assets	$ 4,008	$ 696	$ 195	$ 7,327	$ (1,688)	$ 10,538
Gross property additions	$ 531	$ 17	$ 3	$ 37	$	$ 588

(1) Includes unrealized losses of $474 million, $76 million and $14 million for Mid-Atlantic, Northeast and Other Operations, respectively.
(2) Includes unrealized losses of $5 million for Mid-Atlantic and unrealized gains of $33 million for Northeast.

Table of Contents

Operating Segments

	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
			(in millions)			
2006:						
Operating revenues[1]	$ 1,901	$ 811	$ 171	$ 204	$	$ 3,087
Cost of fuel, electricity and other products[2]	583	464	56	86	(38)	1,151
Gross margin	1,318	347	115	118	38	1,936
Operating Expenses:						
Operations and maintenance	333	116	63	80		592
Depreciation and amortization	74	25	13	25		137
Impairment losses		118		1		119
Loss (gain) on sales of assets, net	(7)	(46)		(40)	44	(49)
Total operating expenses	400	213	76	66	44	799
Operating income	918	134	39	52	(6)	1,137
Total other expense (income), net	(4)	9	(34)	128		99
Income (loss) from continuing operations before reorganization items and income taxes	922	125	73	(76)	(6)	1,038
Reorganization items, net		(164)				(164)
Provision (benefit) for income taxes		2		(552)		(550)
Income from continuing operations	$ 922	$ 287	$ 73	$ 476	$ (6)	$ 1,752
Total assets	$ 3,947	$ 1,264	$ 449	$ 5,276	$ (3,078)	$ 7,858
Gross property additions	$ 112	$ 12	$ 1	$ 14	$	$ 139

(1) Includes unrealized gains of $519 million, $119 million, $3 million and $116 million for Mid-Atlantic, Northeast, California, and Other Operations, respectively.

(2) Includes unrealized losses of $35 million, $58 million and $9 million for Mid-Atlantic, Northeast and Other Operations, respectively.

	Geographic Areas Property, Plant and Equipment and Other Intangible Assets					
	Mid-Atlantic	Northeast	California	Other Operations	Eliminations	Total
			(in millions)			
At December 31, 2008	$ 3,565	$ 396	$ 138	$ 111	$ (799)	$ 3,411
At December 31, 2007	$ 2,999	$ 381	$ 153	$ 62	$ (799)	$ 2,796

Table of Contents

15. Quarterly Financial Data (Unaudited)

Summarized quarterly financial data for 2008 and 2007, is as follows (in millions except per share data):

	Quarters Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Operating revenue	$ 302(1)	$ (393)(2)	$ 2,172(3)	$ 1,107(4)
Cost of fuel, electricity and other products	240(1)	166(2)	360(3)	293(4)
Operating income (loss)	(133)	(790)	1,638	626
Income (loss) from continuing operations	(154)	(832)	1,607	594
Income (loss) from discontinued operations	2	49		(1)
Consolidated net income (loss)	(152)	(783)	1,607	593
Weighted average shares outstanding basic	216	201	175	151
Income (loss) from continuing operations per weighted average shares outstanding basic	(0.71)	(4.14)	9.18	3.94
Net income (loss) per weighted average shares outstanding basic	(0.70)	(3.90)	9.18	3.93
Weighted average shares outstanding diluted	216	201	185	151
Income (loss) from continuing operations per weighted average shares outstanding diluted	(0.71)	(4.14)	8.69	3.94
Net income (loss) per weighted average shares outstanding diluted	$ (0.70)	$ (3.90)	$ 8.69	$ 3.93