MIRANT CORP
Form 10-K
March 01, 2007

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, 2006

Or

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

For the Transition Period from to

Mirant Corporation

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of Incorporation or Organization)	**001 16107** (Commission File Number)	**58 2056305** (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 whether the registrant is a well-known seasoned issuer (as defined by Rule 405 of the Securities Act). o Yes x No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. o 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 o 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. o

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

x Large Accelerated Filer o Accelerated Filer o Non-accelerated Filer

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

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

Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $8,041,023,653 on June 30, 2006 (based on $26.80 per share, the closing price in the daily composite list for transactions on the New York Stock Exchange that day). As of January 31, 2007, there were 255,974,046 shares of the registrant s Common Stock, $0.01 par value per share, outstanding.

TABLE OF CONTENTS

Glossary of Certain Defined Terms

ACO Administrative Compliance Order.

AEP American Electric Power, Inc.

APB Accounting Principles Board.

APB 18 APB Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stocks*.

APB 22 APB Opinion No. 22, *Disclosure of Accounting Policies*.

APSA Asset Purchase and Sale Agreement.

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 runs continuously.

BOT The Philippine Government s build, operate and transfer program.

CAIR Clean Air Interstate Rule.

CAISO California Independent System Operator.

Cal DWR California Department of Water Resources.

Cal PX California Power Exchange.

CAMR Clean Air Mercury Rule.

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

CFTC Commodity Futures Trading Commission.

Clean Air Act Federal Clean Air Act.

Clean Water Act Federal Water Pollution Control Act.

CO Carbon monoxide.

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.

CUC Curacao Utilities Company.

DOE United States Department of Energy.

DOJ United States Department of Justice.

DP&L Dayton Power & Light.

EBITDA Earnings before interest, taxes, depreciation and amortization.

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

EITF 04-13 EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*.

EITF 06-3 EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation).*

EOB California Electricity Oversight Board.

EPA United States Environmental Protection Agency.

EPAct 2005 Energy Policy Act of 2005.

EPS Earnings per Share.

ERCOT Electric Reliability Council of Texas.

ERISA Employee Retirement Income Security Act of 1974.

FASB Financial Accounting Standards Board.

FERC Federal Energy Regulatory Commission.

FIN FASB Interpretation.

FIN 46R FIN No. 46R, *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 AUG AIR-1 FSP AUG AIR-1, *Accounting for Planned Major Maintenance Activities.*

FSP FAS 13-2 FSP FAS 13-2, *Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction.*

FSP FIN 46R-6 FASB Staff Position FASB Interpretation 46R-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R.*

GAAP Generally accepted accounting principles in the United States.

Grand Bahama Power Grand Bahama Power Company.

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

Hudson Valley Gas Hudson Valley Gas Corporation.

IBEW International Brotherhood of Electrical Workers.

ICE 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.

JEP Jamaica Energy Partners.

JPPC Jamaica Private Power Company Limited.

JPS Jamaica Public Service Company Limited.

LIBOR London InterBank Offered Rate.

LICAP Locational installed capacity plan.

LTSA Long term service agreement.

Massachusetts DEP Massachusetts Department of Environmental Protection.

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.

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 JPS Finance Mirant JPSCO Finance LTD.

Mirant Lovett Mirant Lovett, LLC.

Mirant Mid-Atlantic Mirant Mid-Atlantic, LLC.

Mirant New York Mirant New York, Inc.

Mirant North America Mirant North America, LLC.

Mirant NY-Gen Mirant NY-Gen, LLC.

Mirant Pagbilao Mirant Pagbilao Corporation.

Mirant Peaker Mirant Peaker, LLC.

Mirant Potomac River Mirant Potomac River, LLC.

Mirant Power Purchase Mirant Power Purchase, LLC.

Mirant Sual Mirant Sual Corporation.

Mirant Sugar Creek Mirant Sugar Creek, LLC.

Mirant Trinidad Investments Mirant Trinidad Investments, LLC.

Mirant Zeeland Mirant Zeeland, LLC.

MISO Midwest Independent Transmission System Operator.

MMbtu Million British Thermal Units.

MW Megawatt.

MWh Megawatt hour.

NAAQS National ambient air quality standards.

NEPOOL New England Power Pool.

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

NO2 Nitrogen dioxide.

NOL Net operating loss.

NOV Notice of violation.

NOx Nitrogen oxides.

NPC National Power Corporation.

NSR New source review.

NSTAR NSTAR Electric and Gas Corporation.

NYISO Independent System Operator of New York.

NYSDEC New York State Department of Environmental Conservation.

NYSE New York Stock Exchange.

OCI Other comprehensive income.

Ohio Edison Ohio Edison Company.

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.

Panda Panda-Brandywine, LP.

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

Pension Protection Act Pension Protection Act of 2006.

Pepco Potomac Electric Power Company.

PG&E Pacific Gas & Electric Company.

PILOT Payments in lieu of taxes.

PJM Pennsylvania-New Jersey-Maryland Interconnection, LLC.

PM10 Particulate matter that is 10 microns or less in size.

PowerGen The Power Generation Company of Trinidad and Tobago.

PPA Power purchase agreement.

PUHCA Public Utility Holding Company Act of 1935.

PURPA Public Utility Regulatory Policies Act of 1978.

Reserve Margin Excess capacity over peak demand.

RMR Reliability-must-run.

RPM Reliability Pricing Model.

RTO Regional transmission organization.

SAB SEC Staff Accounting Bulletin.

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

SAB No. 108 SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*.

SCE Southern California Edison Company.

SEC U.S. Securities and Exchange Commission.

Securities Act The Securities Act of 1933.

SFAS Statement of Financial Accounting Standards Board.

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

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

SFAS No. 123 SFAS No. 123, *Accounting for Stock-Based Compensation*.

SFAS No. 123R SFAS No. 123R, *Share-Based Payment.*

SFAS No. 132R SFAS No. 132R, *Employers Disclosures about Pensions and Other Postretirement Benefits an amendment of FASB Statements No. 87, 88, and 106.*

SFAS No. 133 SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

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

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

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

SFAS No. 153 *SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29.*

SFAS No. 155 SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*.

SFAS No. 156 SFAS No. 156, *Accounting for Servicing of Financial Assets an amendment of FASB Statement No. 140.*

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

SFAS No. 158 SFAS No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans: an amendment of FASB Statements No. 87, 88, 106, and 132R.*

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

Shady Hills Shady Hills Power Company, L.L.C.

SO2 Sulfur dioxide.

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

T&TEC Trinidad and Tobago Electricity Commission.

The Tokyo Electric Power Company The Tokyo Electric Power Company, Incorporated.

TPA Transition power agreement.

UWUA Utility Workers Union of America.

VaR Value-at-risk.

VIE Variable interest entity.

Virginia DEQ Virginia Department of Environmental Quality.

West Georgia West Georgia Generating Company, L.L.C.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING 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, in addition to historical information. 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, plan, anticipate, estimate, predict, t 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; changes in state, federal and other regulations (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 assets to perform as expected, including outages for unscheduled maintenance or repair, and the timely completion of the repairs on the Sual generating facility;

- our ability to divest our Caribbean business at a price and on terms that we would be willing to accept, and our ability to consummate the sale of our Philippine business and the sale of six of our U.S. intermediate and peaking natural gas-fired plants, as well as any adverse impact on our credit ratings that may result from such sales;

- changes in market conditions, including developments in the supply, demand, volume and pricing of electricity and other commodities in the energy markets, or the extent and timing of the entry of additional competition in our markets or those of our subsidiaries and affiliates;

- increased margin requirements, market volatility or other market conditions that could increase our obligations to post collateral beyond amounts which are expected;

- our inability to access effectively the over-the-counter and exchange-based commodity markets or changes in commodity market liquidity or other commodity market conditions, which may affect our ability to engage in asset management and proprietary trading activities as expected, or result in material extraordinary gains or losses from open positions in fuel oil or other commodities;

- deterioration in the financial condition of our counterparties and the resulting failure 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 generation units adequately for all of their costs;

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

- our inability to enter into intermediate and long-term contracts to sell power and procure fuel, including its transportation, on terms and prices acceptable to us;

3

- legislative and regulatory initiatives and changes in the application of laws and regulations by national and local governments, including increases in tax rates or assessments, in non-U.S. jurisdictions in which our subsidiaries operate;
- factors that affect the operations of our international subsidiaries, such as political instability, local security concerns, tax increases, expropriation of property, cancellation of contract rights and environmental regulations;
- 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;
- our ability to obtain adequate supply and delivery of fuel for our facilities;
- curtailment of operations due to transmission constraints;
- environmental regulations that restrict our ability or render it uneconomic to operate our business, including regulations related to the emission of carbon dioxide 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;
- war, terrorist activities or the occurrence of a catastrophic loss;
- the fact that our New York subsidiaries remain in bankruptcy;
- our substantial 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 and Mirant Asia-Pacific Limited contained in their financing agreements and restrictions on Mirant Mid-Atlantic contained in its leveraged lease documents, which may affect our ability to access the cash flow of those subsidiaries to make debt service and other payments;
- the resolution of claims and obligations that were not resolved during the Chapter 11 process that may have a material adverse effect on our results of operations; and
- the disposition of the pending litigation described in this Form 10-K.

Many of these risks 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.

4

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 under 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 o after January 3, 2006, as further discussed in Item 1. Business.

PART I

Item 1. ***Business***

Overview

We generate revenue primarily through the production of electricity in the United States, the Philippines and the Caribbean. As of December 31, 2006, we owned or leased 17,522 MW of electric generating capacity. Mirant Corporation was incorporated in Delaware on September 23, 2005, and is the successor to a corporation of the same name that was formed in Delaware on April 3, 1993. This succession occurred by virtue of the transfer of substantially all of Old Mirant s assets to New Mirant in conjunction with Mirant s emergence from bankruptcy protection on January 3, 2006. Old Mirant was then renamed and transferred to a trust, which is not affiliated with new Mirant. New Mirant serves as the corporate parent of the business enterprise and, pursuant to the Plan of Reorganization (the Plan) that was approved in connection with old Mirant s emergence from bankruptcy, has no successor liability for any unassumed obligations of old Mirant.

In the third quarter of 2006, we commenced separate auction processes to sell our Philippine (2,203 MW) and Caribbean (1,050 MW) businesses and certain of our U.S. natural gas-fired assets totaling 3,619 MW, including our Zeeland (903 MW), West Georgia (613 MW), Shady Hills (469 MW), Sugar Creek (561 MW), Bosque (546 MW) and Apex (527 MW) facilities. See Note 3 to our consolidated financial statements for additional information regarding the treatment of these businesses and assets as discontinued operations as a result of these decisions.

On December 11, 2006, we entered into a definitive purchase and sale agreement with a consortium of The Tokyo Electric Power Company and Marubeni Corporation for the sale of our Philippine business for a purchase price of $3.424 billion, plus a working capital adjustment at the closing. After the payment of related debt, which is estimated to be $642 million at the closing, the net proceeds to Mirant are expected to be $3.121 billion after transaction costs. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions and the return to operation of both units of the Sual plant.

On January 15, 2007, we entered into a definitive purchase and sale agreement with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively, LS Power), for the sale of six U.S. natural gas-fired plants for a purchase price of $1.407 billion, which includes estimated working capital and certain surplus generating equipment. After the payment of $83 million of related debt, the net proceeds are expected to be $1.307 billion after transaction costs. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions.

The auction and due diligence processes in respect of the sale of the Caribbean business are under way and the sale of the Caribbean business is expected to close by mid-2007.

After giving effect to the aforementioned sales, our continuing operations of 10,650 MW will consist of the ownership, long-term lease and operation of power generation facilities located in the Mid-Atlantic and Northeast regions of the United States and in California, and energy trading and marketing operations in Atlanta.

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 be found at www.mirant.com. We will provide print copies of these documents to any shareholder upon written request to Corporate Secretary, Mirant Corporation, 1155 Perimeter Center West, Atlanta, Georgia 30338-5416. Information contained in our website is not incorporated into this Form 10-K.

U.S. Competitive Environment

Historically, vertically integrated electric utilities with monopolistic control over franchised territories dominated the power generation industry in the United States. The enactment of the PURPA, and the subsequent passage of the Energy Policy Act of 1992, fostered the growth of independent power producers. During the 1990s, a series of regulatory policies were partially implemented at both the federal and state levels to encourage competition in wholesale electricity markets.

As a result, independent power producers built new generating plants, purchased plants from regulated utilities and marketed wholesale power. ISOs and RTOs were created to administer the new markets and maintain system reliability. Beginning in 2001, however, in response to extreme price volatility and electricity shortages in California, regulators began to re-examine the nature and pace of deregulation of wholesale electricity markets, and that re-examination is continuing.

Independent power producers, as well as utilities, constructed primarily natural gas-fired plants in the 1990s because natural gas prices were low and such plants could be constructed more quickly and were less expensive to permit and build than nuclear and coal-fired plants. Stagnation in the growth of natural gas supplies, the increased demand from new generation facilities and the damage caused by hurricanes Katrina and Rita resulted in a sharp increase in the price of natural gas during 2005. In 2006, there was volatility in natural gas prices, with a substantial decline from their 2005 highs. Although natural gas prices have declined from 2005, natural gas prices remain high compared to historical prices. High natural gas prices have contributed to high electricity prices.

A number of factors combined to create excess generating capacity in certain U.S. markets, including a substantial increase in construction of generation facilities following the deregulation efforts described above, capital investments by utilities aimed at extending the lives of older units and the inability to decommission certain plants for reliability reasons. In certain markets in the United States, that excess has been absorbed or is close to being absorbed. Electricity demand has been growing and supply has not appreciably increased. Given the substantial time necessary to permit and construct new power plants, we think that the markets in the United States in which we operate need to begin the process now of adding generating capacity to meet growing demand. A number of key ISOs have implemented capacity markets as a way to encourage such construction of additional generation, but it is not clear whether independent power producers will be sufficiently incentivized to build this new generation.

Falling reserve margins, as well as high electricity prices as a result of high natural gas prices, have led to renewed interest in new coal-fired or nuclear plants. Coal-fired generation and nuclear generation currently account for approximately 50% and 20%, respectively, of the electricity produced in the United States. There is substantial environmental opposition to building either coal-fired or nuclear plants.

In light of the foregoing market conditions, some regulated utilities are proposing to construct coal-fired units or nuclear plants, in some cases with governmental subsidies or under legislative mandate. Unlike independent power producers like us, these utilities often are able to recover fixed costs through regulated retail rates, allowing them to build without relying on market prices to recover their investments.

Many regulated utilities are also seeking to acquire distressed assets or make substantial environmental improvements to existing coal plants, in each case with regulatory assurance that the utility will be permitted to recover its costs, plus earn a return on its investment. Success by utilities in those efforts may put independent power producers at a disadvantage because they rely heavily on market prices rather than regulatory assurances.

Business Segments

Previously, we managed our business as three operating segments: United States, Philippines and Caribbean. In 2006, we commenced separate auction processes to dispose of our Caribbean and Philippine businesses and certain U.S. natural gas-fired assets. The planned sales have resulted in the reclassification of the revenues and expenses of these businesses and assets to discontinued operations and the reclassification of the related assets and liabilities to held for sale for all periods presented. In the fourth quarter of 2006, we re-evaluated the business segments of our continuing operations. As a result, we now have four operating segments: Mid-Atlantic, Northeast, California and Other Operations. Other Operations includes proprietary trading and fuel oil management activities and gains and losses related to a contractual arrangement entered into with Pepco with respect to certain PPAs, including Pepco s long-term PPAs with Panda and Ohio Edison (the Back-to-Back Agreement). For selected financial information about our business segments, see Note 20 to our consolidated financial statements contained elsewhere in this report. See Item 2. Properties for a complete list of our assets. We have restated corresponding items of segment information for prior periods to conform with our current operating segments.

The table below summarizes selected financial information for our business segments, after giving effect to the pending sales, for the year ended December 31, 2006 (dollars in millions):

	Revenues	%	Gross Margin	%	Operating Income	%
Business Segment:						
Mid-Atlantic	$ 1,901	61 %	$ 1,318	68 %	$ 918	81 %
Northeast	827	27 %	358	18 %	128	11 %
California	171	6 %	115	6 %	39	4 %
Other Operations	204	6 %	118	6 %	52	5 %
Eliminations		%	38	2 %	(6)	(1)%
Total Continuing Operations	$ 3,103	100 %	$ 1,947	100 %	$ 1,131	100 %

Overview

Our core business is the production and sale of electrical energy, electrical capacity (the ability to produce electricity on demand) and ancillary services (services that are ancillary to transmission services). Our customers are ISOs, utilities, municipal systems, aggregators, electric cooperative utilities, producers, generators, marketers and large industrial customers.

Ownership and Operation of Electricity Generation Assets

As of December 31, 2006, our continuing operations consist of owned or leased generation facilities with 10,650 MW of generating capacity. 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 generation capacity includes approximately 32% baseload units, 48% intermediate units and 20% peaking units.

Commercial Operations

Our commercial operations consist primarily of procuring fuel, dispatching electricity, hedging the production and sale of electricity by our generating facilities, fuel oil management and providing logistical support for the operation of our facilities (for example, by procuring transportation for coal). We often sell the electricity we produce into the wholesale market at prices in effect at the time we produce it (spot price). Those prices are volatile, however, 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 into the wholesale market and purchases of fuel and emissions allowances to allow us to produce and sell the electricity for different periods of time. We procure these hedges in OTC transactions or 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. 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 that we do not produce and some fuel and emissions allowances that we do not need to produce electricity (proprietary trading). Proprietary trading is a small part of our commercial operations, which we do in order to gain information about the markets to support our asset management and to take advantage of selected opportunities that we may identify from time to time. All of our commercial activities are governed by a comprehensive Risk Management Policy, which requires that our hedging activities with respect to our assets be risk-reducing and sets limits on the size of trading positions and VaR in our proprietary trading activities.

We use dispatch models to make 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 generation facilities into the day-ahead energy market and sell ancillary services through the ISO markets. We work with the ISOs and RTOs in real time to ensure that our generation facilities are dispatched economically to meet the reliability needs of the market.

We economically hedge a substantial portion of our Mid-Atlantic coal-fired baseload generation and certain of our Northeast coal, gas and oil-fired generation through OTC transactions. However, we generally do not hedge most of our intermediate and peaking units. In 2006 and thus far in 2007, our Mirant Mid-Atlantic subsidiary entered into financial swap transactions resulting in Mirant Mid-Atlantic being economically hedged for approximately 92%, 93%, 97% and 38% of its expected on-peak coal-fired baseload generation in 2007, 2008, 2009 and 2010, respectively. The financial swap transactions include new hedges in addition to the previously disclosed January 2006 hedges. These transactions are senior unsecured obligations of Mirant Mid-Atlantic and do not require the posting of cash collateral either for initial margin or for securing exposure due to changes in power prices. As of February 26, 2007, our total portfolio is economically hedged approximately 83%, 47%, 35% and 14% for 2007, 2008, 2009 and 2010, respectively. The corresponding fuel hedges are approximately 81%, 27%, 15% and 0% for 2007, 2008, 2009 and 2010 respectively.

While OTC transactions make up a substantial portion of our economic hedge portfolio, Mirant Energy Trading also sells non-standard, structured products to customers. In addition to energy, these products typically include capacity, ancillary services and other energy products. We view these transactions as a method of mitigating the risk of certain portions of our business that are not easy to economically hedge in the OTC market. Typically, we are able to sell these products at a higher premium than standard products. Additionally, we have facilities operating under long-term contracted capacity and RMR contracts. At December 31, 2006, our contracted capacity pursuant to these agreements was 2,347 MW with terms expiring through October 2011.

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 generation facilities, we purchase coal from a variety of suppliers under contracts with terms of varying lengths, some of which extend to 2009. For our oil-fired units, fuel typically is purchased under short-term contracts linked to a transparent oil index price. For our gas-fired units, fuel typically is purchased under short-term contracts with a variety of suppliers on a day-ahead or monthly basis.

Our coal supply primarily comes from the Central Appalachian and Northern Appalachian coal regions. All of our coal is delivered by rail, although we are in the process of permitting a barge unloading facility at our Morgantown station that will enable us to receive coal by an alternative transportation source beginning in 2008. We monitor coal supply and delivery logistics carefully, and, despite occasional interruptions of scheduled deliveries, to date we have managed to avoid any significant impact to our operations. We maintain an inventory of coal at our coal-fired facilities for this purpose. Interruptions of scheduled deliveries can occur because of supply disruptions due to strikes or other reasons or as a result of rail system disruptions due to weather or other reasons.

Mid-Atlantic Region

We own or lease four generation facilities in the Mid-Atlantic region with a total generation capacity of 5,256 MW: Chalk Point, Morgantown, Dickerson and Potomac River. Our Mid-Atlantic region had a combined 2006 capacity factor (average percentage of full capacity used over a year) of 36%. Our Mid-Atlantic facilities are located in Maryland and Virginia and were acquired from Pepco in December 2000. The Chalk Point facility is our largest generation facility in the region. It consists of two coal-fired baseload units, two oil and gas-fired intermediate units and two oil-fired and five gas and oil-fired peaking units, for a total generation capacity of 2,429 MW. Our next largest facility in the region is the Morgantown facility. It consists of two dual-fueled (coal and oil) baseload units and six oil-fired peaking units, for a total generation capacity of 1,492 MW. The Dickerson facility has three coal-fired baseload units, and one oil-fired and two gas and oil-fired peaking units, for a total generation capacity of 853 MW. The Potomac River station has three coal-fired baseload units and two coal-fired intermediate units, for a total generation capacity of 482 MW.

Power generated by our Mid-Atlantic facilities is sold into the PJM market. For a discussion of the PJM market, see Regulatory Environment below. We have participated indirectly in standard offer service auctions in Maryland and Washington, D.C. Power sales, made either directly through these auctions or indirectly through subsequent market transactions that are a result of the auction process, serve as economic hedges for the Mid-Atlantic assets.

On August 24, 2005, power production at all five units of the Potomac River generating facility was temporarily halted in response to a letter from the Virginia DEQ. On August 25, 2005, the District of Columbia Public Service Commission filed an emergency petition and complaint with the FERC and the DOE to prevent the shutdown of the Potomac River facility. The matter remains pending before the FERC and the DOE. On December 20, 2005, due to a determination by the DOE that an emergency situation existed with respect to the reliability of the supply of electricity to central Washington, D.C., the DOE ordered Mirant Potomac River to generate electricity at the Potomac River generating facility, as requested by PJM, during any period in which one or both of the transmission lines serving central Washington, D.C. are out of service due to a planned or unplanned outage. In addition, the DOE ordered Mirant Potomac River, at all other times, for electric reliability purposes, to keep as many units in operation as possible and to reduce the start-up time of units not in operation without contributing to any NAAQS exceedances. The DOE required Mirant Potomac River to submit a plan that met these requirements, on or before December 30, 2005. The order further provides that Mirant Potomac River and its customers should agree to mutually satisfactory terms for any costs incurred by it under this order or just and reasonable terms shall be established by a supplemental order. Certain parties filed for rehearing of the DOE order, and on February 17, 2006, the DOE issued an order granting rehearing solely for purposes of considering further the rehearing requests. Mirant Potomac River submitted an operating plan in accordance with the order. On January 4, 2006, the DOE issued an interim response to Mirant Potomac River s operating plan authorizing operation of the units of the Potomac River generating facility on a reduced basis, but making it possible to bring the entire plant into service within approximately 28 hours when necessary for reliability purposes. The DOE s order expires July 1, 2007, but Mirant Potomac River expects it will be able to continue to operate these units after that expiration.

In a letter received December 30, 2005, the EPA invited Mirant Potomac River and the Virginia DEQ to work with the EPA to ensure that Mirant Potomac River s operating plan submitted to the DOE adequately addressed NAAQS issues. The EPA also asserted in its letter that Mirant Potomac River did not immediately undertake action as directed by the Virginia DEQ s August 19, 2005, letter and failed to comply with the requirements of the Virginia State Implementation Plan established by that letter. Mirant Potomac River received a second letter from the EPA on December 30, 2005, requiring Mirant to provide certain requested information as part of an EPA investigation to determine the Clean Air Act compliance status of the Potomac River generating facility.

On June 1, 2006, Mirant Potomac River and the EPA executed an ACO by Consent to resolve the EPA s allegations that Mirant Potomac River violated the Clean Air Act by not immediately shutting down all units at the Potomac River facility upon receipt of the Virginia DEQ s August 19, 2005, letter and to assure an acceptable level of reliability to the District of Columbia. The ACO (i) specifies certain operating scenarios and SO2 emissions limits for the Potomac River facility, which scenarios and limits take into account whether one or both of the 230kV transmission lines serving Washington, D.C. are out of service; (ii) requires the operation of trona injection units to reduce SO2 emissions; and (iii) requires Mirant Potomac River to undertake a model evaluation study to predict ambient air quality impacts from the facility s operations. In accordance with the specified operating scenarios, the ACO permits the facility to operate using a daily predictive modeling protocol. This protocol allows Mirant Potomac River to schedule the facility s level of operations based on whether computer modeling predicts a NAAQS exceedance, based on weather and certain operating parameters. On June 2, 2006, the DOE issued a letter modifying its January 6, 2006, order to direct Mirant Potomac River to comply with the ACO in order to ensure adequate electric reliability to the District of Columbia. Mirant Potomac River is operating the Potomac River facility in accordance with the ACO and has been able to operate all five units of the facility most of the time under the ACO.

Northeast Region

We own generating facilities in the Northeast region consisting of 3,047 MW of capacity. Our Northeast region had a combined 2006 capacity factor of 17%. The Northeast region is comprised of our assets located in New York and New England. The subsidiaries that own our New York facilities remain in bankruptcy. For further information, see Item 3. Legal Proceedings. Generation is sold from our Northeast facilities through a combination of bilateral contracts, spot market transactions and structured transactions.

New York. Our New York generating facilities were acquired from Orange and Rockland and Consolidated Edison Company of New York, Inc. in June 1999. The New York generating facilities consist of the Bowline and Lovett facilities and various smaller generating facilities comprising a total of 1,656 MW of capacity. The Bowline facility is a 1,125 MW dual-fueled (natural gas and oil) facility comprised of two intermediate/peaking units. The Lovett facility consists of two baseload units capable of burning coal and gas comprising a total of 348 MW and a peaking unit capable of burning gas or oil comprising 63 MW. The smaller New York generating facilities have a total capacity of 120 MW and consist of the Hillburn and Shoemaker facilities, which each contain a single peaking unit capable of running on natural gas or jet fuel, and the Mongaup 1-4, Swinging Bridge 1-2 and Rio 1-2 facilities, which each contain a hydroelectric intermediate unit. We also had an operational interest in the Grahamsville facility, pursuant to a sublease between Orange and Rockland and Mirant NY-Gen. On October 31, 2006, we transferred the Grahamsville facility to Orange and Rockland for transfer to the City of New York. The capacity, energy and ancillary services from our New York generating units are sold into the bilateral markets and into the markets administered by the NYISO through Mirant Energy Trading. For a discussion of NYISO, see Regulatory Environment below.

Our current plan is to retire units 3 and 5 at the Lovett facility by April 30, 2007, and the remaining unit by April 30, 2008, as required under the terms of a consent decree entered into on June 11, 2003, to resolve issues related to NSR regulations promulgated under the Clean Air Act (the 2003 Consent Decree) if certain environmental controls are not added to the two units of the Lovett facility that burn

11

coal. We are also considering scenarios that allow continued operations past April 2007 and April 2008 as we continue to work with the State of New York and other parties to achieve a solution related to environmental controls and to allow Lovett to continue to contribute to the reliability of the electric system of the State of New York. In order for the facility to remain viable on a long-term basis, we need to accomplish two primary tasks. First, we need to reach agreement with the State of New York on amendments to the 2003 Consent Decree that would address the installation of environmental equipment. Second, because current market conditions do not allow Mirant Lovett to recover the necessary returns to fund the installation of environmental controls specified under the 2003 Consent Decree, we are seeking an agreement with a third party assuring us of enough revenue to justify the required capital expenditures. Our view is that the Lovett facility is necessary to the provision of reliable electricity to the Lower Hudson Valley and other areas within the New York Control Area.

In the fourth quarter of 2006, the Bankruptcy Court approved a settlement of disputed property taxes among Mirant Bowline, Mirant Lovett, Hudson Valley Gas and various New York tax jurisdictions. The settlement resolves pending disputes regarding refunds sought by us for property taxes paid for 1995 through 2003 and unpaid taxes assessed for 2003 through 2006. Under the settlement, in February 2007 we received refunds totaling approximately $163 million for 1995 through 2002, and paid unpaid taxes of approximately $115 million for 2003 through 2006, resulting in receipt of a net cash amount of $48 million. As a result of the refund and the reduction in unpaid taxes under the settlement, we recognized a gain of approximately $244 million in the fourth quarter of 2006. Of the $244 million gain recognized, $163 million is included in reorganization items, net, and $94 million is a reduction in operations and maintenance expense in the consolidated statements of operations. These amounts are partially offset by $13 million in interest expense.

In May 2005, a sinkhole was discovered in the dam of our Swinging Bridge facility. In response, Mirant NY-Gen filled this sinkhole, inspected for damage the dam s slopes and the enclosed pipe that delivers water from the reservoir to the generator, drew down the lake level and cleaned the diversion tunnel. Mirant NY-Gen s analysis indicates that the most probable cause of the sinkhole was erosion of soil comprising the dam from water flow through a hole in the pipe that delivers water from the reservoir to the generator. The dam is stabilized, and Mirant NY-Gen is performing additional remediation repairs. By letter dated June 14, 2006, the FERC authorized Mirant NY-Gen to proceed with its remediation plan for the sinkhole. The FERC has also concurred with the results of Mirant NY-Gen s flood study for its Swinging Bridge, Rio and Mongaup generation facilities, which study concluded that no additional remediation is required. On June 29, 2006, the Bankruptcy Court authorized Mirant NY-Gen to proceed with implementation of the remediation plan. The current estimated cost to remediate the dam at Swinging Bridge is approximately $29 million, of which approximately $22 million had been incurred through December 31, 2006. Mirant NY-Gen currently expects to recover insurance proceeds for a portion of these repair costs. The Bankruptcy Court has approved a debtor-in-possession loan to Mirant NY-Gen from Mirant Americas under which Mirant Americas, subject to certain conditions, would lend up to $16.5 million to Mirant NY-Gen to provide funding for the repairs on the Swinging Bridge dam.

On January 26, 2007, Mirant New York, Mirant Bowline, and Hudson Valley Gas (collectively the Emerging New York Entities) filed a Supplemental Joint Chapter 11 Plan of Reorganization of the Emerging New York Entities (the Supplemental Plan) with the Bankruptcy Court. For more detail concerning the Supplemental Plan, see Item 3. Legal Proceedings, Chapter 11 Proceedings.

On January 31, 2007, Mirant New York entered into an agreement for the sale of Mirant NY-Gen, which owns the Hillburn and Shoemaker gas turbine facilities and the Swinging Bridge, Rio and Mongaup hydroelectric generating facilities. An auction process supervised by the Bankruptcy Court is required before bankruptcy court approval may occur. The estimated sales price of $3 million is subject to adjustments for working capital and certain dam remediation efforts that are ongoing at the Swinging Bridge facility. The transaction is expected to close in the second quarter of 2007.

New England. Our New England generating facilities, with a total capacity of 1,391 MW, were acquired from subsidiaries of Commonwealth Energy System and Eastern Utilities Associates in December 1998. The New England generating facilities consist of the Canal station, the Kendall station, the Martha s Vineyard diesels and an interest in the Wyman unit 4 facility. The Canal and Kendall facilities, located in close proximity to Boston, consist of 1,112 MW and 256 MW of generating capacity, respectively, and are designed to operate during periods of intermediate and peak demand. The Kendall facility is a combined cycle facility which produces both steam and electricity for sale. Both the Canal and Kendall facilities possess the ability to burn both natural gas and fuel oil. The Martha s Vineyard diesels, with 14 MW of capacity, supply electricity on the island of Martha s Vineyard during periods of high demand or in the event of a transmission interruption. The Wyman unit 4 interest is an approximate 1.4% ownership interest (equivalent to 9 MW) in the 614 MW Wyman unit 4 located on Cousin s Island, Yarmouth, Maine. Wyman unit 4 is primarily owned and operated by the Florida Power and Light Group.

The capacity, energy and ancillary services from our New England generating units are sold into the NEPOOL bilateral markets and into the markets administered by the ISO-NE through Mirant Energy Trading. For a discussion of the NEPOOL and the ISO-NE, see Regulatory Environment below.

We had determined that market fundamentals in NEPOOL did not permit us to operate the Kendall facility on an economical basis as a merchant facility. We therefore had planned to shut down, at least temporarily, the Kendall facility from January 2005 through December 2007, with the possibility of restarting operations as early as January 2008. However, the ISO-NE determined that part of the capacity of the Kendall facility was needed for reliability and proposed an RMR agreement with a term lasting until the earlier of (1) the date a locational installed capacity cost recovery mechanism applicable to the Kendall facility is in place or (2) 120-days after we are provided written notice. We entered into and received FERC approval for an agreement with NSTAR and ISO-NE, which included the RMR agreement. On December 28, 2006, ISO-NE provided notice that the RMR agreement shall terminate effective May 1, 2007. A locational installed capacity market has been implemented in New England and, as a result and coupled with additional steam sales, there are no plans to shut down the Kendall facility in 2007.

California

Our California facilities, with a total capacity of 2,347 MW, are primarily gas-fired generating facilities and consist of the Pittsburg, Contra Costa and Potrero facilities, which have generation capacity of 1,311 MW, 674 MW and 362 MW, respectively. Our California facilities had a 2006 capacity factor of 6%.

The Pittsburg and Contra Costa facilities are natural gas facilities and both generate electricity by using gas-fired steam boilers. They are located in Contra Costa County, approximately ten miles apart along the Sacramento/San Joaquin River. The Potrero facility, located in the City of San Francisco, has one natural gas-fired intermediate steam boiler from which it generates electricity and three oil-fired peaking distillate fueled combustion turbines.

Through the end of 2006, the majority of our California assets were subject to RMR arrangements with the CAISO. These agreements are described further under Regulatory Environment below. Our California subsidiaries had the largest portfolio of units that operated under RMR arrangements in California, reflecting that the location of these units is key to electric system reliability. 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 our natural gas-fired units at Pittsburg and Contra Costa, including Pittsburg unit 7 and Contra Costa unit 6. The agreements are for 100% of the capacity from these assets, approximately 2,000 MW. The contracts have varying tenors ranging from one to four years, and include capacity of 1,985 MW for 2007, 2008 and 2009, 1,303 MW for 2010 and 674 MW for 2011. We will receive monthly capacity payments with bonuses and/or penalties based on guaranteed heat rate and availability tolerances. As a result of these contracts, the Pittsburg and Contra Costa units are no longer subject to the RMR agreements. Potrero units 3-6 continue to be subject to the RMR arrangements as described.

On January 14, 2005, we and certain of our subsidiaries entered into a Settlement and Release of Claims Agreement (the California Settlement) with PG&E, SCE, San Diego Gas and Electric Company, the CPUC, the Cal DWR, the EOB and the Attorney General of the State of California and with the Office of Market Oversight and Investigations of the FERC. Pursuant to the settlement agreement that became effective in April 2005, the partially constructed Contra Costa unit 8 project, which is a planned 530 MW combined cycle generating facility, and related equipment (collectively, the CC8 Assets) were transferred to PG&E on November 29, 2006. Mirant Delta received $70 million that under the terms of the settlement had been held in an escrow account to be paid to PG&E if the Contra Costa 8 project was not transferred to it by June 30, 2008. We recognized a gain of $27 million in the fourth quarter of 2006 as a result of these transfers.

Discontinued Operations

Philippines

Our subsidiaries have ownership interests in three generating facilities in the Philippines: Sual (1,218 MW/100% owned), Pagbilao (735 MW/100% owned) and Ilijan (1,251 MW/20% owned). As of December 31, 2006, our net ownership interest in the generating capacity of these facilities was 2,203 MW.

Substantially all of the generation capacity of the Sual and Pagbilao facilities is sold under long-term energy conversion agreements with the Philippine government-owned NPC. NPC acts as both the fuel supplier and the energy purchaser for the Sual and Pagbilao facilities. NPC procures all of the fuel necessary for generation at no cost to the respective operating company.

Under the energy conversion agreements, Sual and Pagbilao receive both fixed capacity fees and variable energy fees. Fixed capacity fees are paid without regard to the dispatch level of the facility. Variable energy fees are paid when the facility generates electricity. Currently, approximately 90% of the revenues with respect to our Philippine operations come from fixed capacity charges. Nearly all of the capacity fees of Sual and Pagbilao are denominated in U.S. dollars. Energy fees and a portion of the capacity fees have both U.S. dollar and Philippine peso components that are indexed to inflation. The majority of the obligations of NPC under the energy conversion agreements are guaranteed by the full faith and credit of the Philippine government.

The energy conversion agreements were executed under the BOT program. The energy conversion agreements for the Sual, Pagbilao and Ilijan facilities expire in October 2024, August 2025 and June 2022, respectively.

In addition to the energy conversion agreements with NPC, our Sual subsidiary has a joint marketing agreement with NPC for excess capacity of 218 MW. Currently, electricity from the excess capacity of our Sual facility is provided to selected customers such as economic zones, industrial customers and private electric distribution companies and cooperatives. As a result of outages at both units of the Sual plant, we are currently purchasing power from NPC to meet our supply obligations. See Sual Outages in Note 3 to the consolidated financial statements where the outages are discussed further.

Real property taxes in the Philippines are levied by applying a locally determined tax rate to the taxable value of property. We are currently the owner of record of the machinery and equipment on which real property taxes are levied but NPC is responsible for payment of real property taxes under the energy conversion agreements for our Pagbilao and Sual power facilities. See Note 3 to the consolidated financial statements contained elsewhere in this report for further discussion of the real property taxes applicable to these facilities.

Caribbean

Our net ownership interest in the generating capacity of our Caribbean plants is 1,050 MW.

Jamaica Public Service Company Limited. We own an 80% interest in JPS, a fully integrated electric utility company that generates, transmits, distributes and sells electricity on the island of Jamaica. JPS operates under a 20-year All-Island Electric License (the License) that expires in 2021 and that provides JPS with the exclusive right to sell power on a retail basis in Jamaica. Under the provisions of the License, JPS is granted the exclusive right to transmit, distribute and supply electricity throughout the island of Jamaica. JPS also has the right to develop new generation capacity subject to a requirement that expansion projects in excess of 20 MW be subjected to a competitive tendering process. In instances of force majeure, the Office of Utilities and Regulation (the OUR) may waive the requirements for competitive tendering. JPS has installed generation capacity of 603 MW, and purchases an additional 196 MW of firm capacity from three independent power producers under long-term purchase agreements and an additional 20 MW of energy from a wind farm on an as-available basis. JPS supplies electric power to approximately 571,000 residential, commercial and industrial customers in Jamaica. JPS is regulated by the OUR under a price cap model with rate cases held every five years and with interim adjustments for changes in inflation, fuel prices, purchase power costs, foreign exchange movements and certain efficiency measures. JPS completed its most recent rate case in June 2004.

Grand Bahama Power Company. We own a 55.4% interest in Grand Bahama Power, a 151 MW integrated electric utility company that generates, transmits, distributes and sells electricity on Grand Bahama Island. Grand Bahama Power has the exclusive right and obligation to supply electric power to the residential, commercial and industrial customers on Grand Bahama Island. As of December 31, 2006, Grand Bahama Power has approximately 19,000 customers. Grand Bahama Power s rates are set by the Grand Bahama Port Authority.

The Power Generation Company of Trinidad and Tobago. We own a 39% interest in PowerGen, a power generation company that owns and operates three power plants located on the island of Trinidad. The electricity produced by PowerGen is provided to T&TEC, which serves approximately 347,000 customers on the islands of Trinidad and Tobago and which holds a 51% interest in PowerGen. PowerGen has a power purchase agreement for approximately 820 MW of capacity and spinning reserve with T&TEC that expires in 2009 and is guaranteed by the government of Trinidad and Tobago. Under this contract, the fuel is provided by T&TEC.

On December 6, 2005, PowerGen and T&TEC executed a 30-year 208 MW power sales agreement. On February 23, 2006, PowerGen began construction of the facility that is to supply the power to be provided under this agreement and estimates a commercial operations date of March 2007.

Curacao Utilities Company. We own a 25.5% interest in CUC at the Isla Refinery in Curacao, Netherlands Antilles. The 153 MW facility provides electricity, steam, desalinated water and compressed air to the refinery and up to 45 MW of electricity to the Curacao national grid.

At December 31, 2006, CUC was in technical default under its $84 million senior debt facility due to delays in completion of generation facilities. To date, CUC s lenders have not exercised their right to terminate the debt facility. CUC is currently pursuing an amendment and a waiver from the lenders and expects to receive it in the first quarter of 2007. In the event the issue is not resolved, our annual dividend payments from this investment may be at risk.

Aqualectra. We own a $40 million convertible preferred equity interest in Aqualectra, an integrated water and electric company in Curacao, Netherlands Antilles, owned by the government. Aqualectra has

electric generating capacity of 235 MW and drinking water production capability of 69,000 cubic meters per day. Aqualectra serves approximately 65,000 electricity and water customers. We receive 16.75% preferred dividends on our $40 million investment on a quarterly basis. As described below, Aqualectra has not paid our September and December 2006 preferred dividends because it is in default under its $87 million credit facility. Aqualectra has a call option and we have a put option, both of which are exercisable through December 31, 2007. We also have an option to convert our convertible preferred equity interest in Aqualectra to common shares through December 31, 2007. Neither we nor Aqualectra have exercised such options at this time.

At December 31, 2006, Aqualectra was in default under its $87 million credit facility because of breaches in financial covenants. Aqualectra is in breach of these covenants primarily due to its inability to pass through escalating fuel costs to its customers. Aqualectra has been in default for breaching these debt covenants in the past but has received waivers from the lenders which allowed the payment of our preferred dividends. A primary condition of the bank waiver was the existence of the energy fund. The energy fund, established by the Island Council and Executive Council of the Island Territory of Curacao, was intended to stabilize the prices of the energy related products on the island for the period 2005 through 2006. The energy fund was designed to provide Aqualectra with recovery of its fuel costs in excess of those recovered from its customers for the period from January 2005 through December 2006. As of December 31, 2006, the energy fund was depleted. The depletion of the fund has caused the bank waiver of the debt covenant breach to expire. Aqualectra requested a waiver from the lenders related to its financial covenant breaches but the lenders have declined to give a waiver until the energy fund is funded by the Curacao government or the Curacao government provides for an increase in the Aqualectra rate structure to allow for the full recovery of its fuel costs. As of December 31, 2006, dividend payments from Aqualectra totaling approximately $3 million are in arrears. Resolution of this issue could take several months and consequently, the receipt of the March 2007 dividend payment could be delayed.

U.S. Natural Gas-Fired Assets

Our six U.S. natural gas-fired intermediate and peaking facilities have a total capacity of 3,619 MW.

The Zeeland facility, located in Zeeland, Michigan, is comprised of simple cycle units totaling 327 MW of capacity and a 576 MW combined cycle facility (903 MW of total capacity). The Zeeland facility is interconnected with the International Transmission Company, which is a member of the MISO and operates under the East Central Area Reliability Coordination Agreement.

The West Georgia facility in Thomaston, Georgia, and the Shady Hills facility in Pasco County, Florida, consist of gas and oil-fired combustion turbines with capacities of 613 MW and 469 MW, respectively. They operate in the Southeastern Electric Reliability Council. Currently, there is no ISO in the Southeastern Electric Reliability Council.

West Georgia has a PPA for a portion of the output of the West Georgia facility that will expire in May 2009. The annual capacity amount nominated by West Georgia is approximately 448 MW. West Georgia receives a capacity payment, start-up payments, and variable operating and maintenance payments on a per MWh basis, and an index-based fuel payment. The PPA allows West Georgia to provide replacement energy from the market to meet its contractual obligations. West Georgia may receive bonuses or incur penalties for availability outside allowable limits. There are no provisions for renewal or extension of the contract. Output of the West Georgia facility not covered by the PPA is sold into the wholesale market by Mirant Energy Trading.

West Georgia has a fuel supply contract which expires in May 2009. West Georgia also has purchased firm gas transportation for 22,500 MMbtu/day for the months of June through September under an agreement that expires in May 2009.

Shady Hills has a tolling agreement with a counterparty that runs through March 2007 for all of the facility s output. A second tolling agreement, which runs through April 2024, will begin at the expiration of the existing agreement. Pursuant to the tolling arrangements, Shady Hills receives a monthly capacity payment, a variable operating and maintenance payment on a per MWh basis, and a start-up payment each time a unit is turned on. The counterparty schedules and delivers all fuel. Shady Hills generates electricity and provides a heat rate and availability guarantee and may receive bonuses and pay penalties when its performance is outside the guaranteed values.

The Sugar Creek facility is a 561 MW combined cycle facility located in West Terre Haute, Indiana. The Sugar Creek facility has the physical capability to be interconnected with either the Cinergy or AEP systems. Cinergy is a member of the MISO, and AEP is a member of the PJM market. The facility is eligible to participate in the energy, capacity and ancillary markets of PJM and MISO.

The Bosque facility located in Laguna Park, Texas, consists of a gas-fired combustion turbine with a corresponding steam turbine with a capacity of 239 MW that is available to serve baseload and intermediate demand. Additionally, Bosque units 1 and 2 are gas-fired peaking facilities with a total capacity of 307 MW. The Bosque facility operates in the ERCOT market. For a discussion of ERCOT, see Regulatory Environment below.

The Apex facility is a 527 MW intermediate gas-fired combined-cycle facility located near Las Vegas, Nevada. Mirant Energy Trading has signed contracts with a third party for 225 MW of capacity and energy from the Apex facility for the period from May 2003 to April 2008.

Regulatory Environment

The electricity industry is subject to comprehensive 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. Any of our subsidiaries that owns a generating facility selling at wholesale or that markets electricity at wholesale outside of ERCOT 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 are subject to FERC oversight of mergers and acquisitions, the disposition of FERC-jurisdictional facilities and the issuance of securities. In addition, under the Natural Gas Act, the FERC has limited jurisdiction over certain resales of natural gas, but does not regulate the prices received by our subsidiary that markets natural gas.

The FERC has authorized our subsidiaries that constitute public utilities under the Federal Power Act to sell energy and capacity at wholesale at market-based rates and has authorized some of these subsidiaries to sell certain ancillary services at wholesale at market-based rates. The majority of the output of the generation facilities owned by our United States subsidiaries that constitute public utilities is sold pursuant to this authorization, although certain of our facilities sell their output under cost-based RMR agreements, as explained below. The FERC may revoke or limit our market-based rate authority if it determines that we possess undue market power in a regional market. The FERC requires that our subsidiaries with market-based rate authority, as well as those with blanket certificate authorization permitting market-based sales of natural gas, adhere to certain market behavior rules and codes of conduct, respectively. If any of our subsidiaries violates the market behavior rules or codes of conduct, the FERC may require a disgorgement of profits or revoke its market-based rate authority or blanket certificate authority. If the FERC were to revoke market-based rate authority, our affected subsidiary would have to file a cost-based rate schedule for all or some of its sales of electricity at wholesale. If the FERC revoked the blanket certificate authority of any of our subsidiaries, certain sales of natural gas would be prohibited.

Our facilities operate in ISO/RTO markets. In areas where ISOs or RTOs control the regional transmission systems, market participants have expanded access to transmission service. ISOs operate real-time and day-ahead energy and ancillary services markets, typically governed by FERC-approved tariffs and market rules. Some RTOs and ISOs also operate capacity markets. Changes to the applicable tariffs and market rules may be requested by market participants, state regulatory agencies and the system operator, and such proposed changes, if approved by the FERC, could have a significant impact on our operations and business plan. While participation by transmission-owning public utilities in ISOs and RTOs has been and is expected to continue to be voluntary, the majority of such public utilities in New England, New York, the Mid-Atlantic and California have joined the respective ISO/RTO.

Our subsidiaries owning generation in the United States were exempt wholesale generators under the PUHCA, as amended, and all of our subsidiaries owning generation outside the United States were either foreign utility companies or exempt wholesale generators. With the repeal of the PUHCA and the adoption of the Public Utility Holding Company Act of 2005, the FERC adopted new regulations effective February 8, 2006, that allow our subsidiaries owning generation in the United States to retain their exempt wholesale generator status as well as allow our subsidiaries owning generation outside of the United States to remain either foreign utility companies or exempt wholesale generators.

State and local regulatory authorities have historically 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 generation may be subject to a variety of state and local regulations, including regulations regarding the environment, health and safety, maintenance and expansion of generation facilities. To the extent that a subsidiary sells electricity at retail in a state with a retail access program, it may be subject to state certification requirements and to bidding rules that provide default service to customers who choose to remain with their regulated utility distribution companies.

Mid-Atlantic Region. Our Mid-Atlantic facilities sell power into the markets operated by PJM, which the FERC approved to operate as an ISO in 1997 and as an RTO in 2002. 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 generators. PJM administers day-ahead and real-time marginal cost 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 cheaper power 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 capacity. PJM operates a capacity market whereby load-serving entities can procure their capacity requirements through a system-wide single clearing price auction. In PJM, all capacity is assumed to be universally deliverable, regardless of its location. PJM has greatly expanded its system to include Allegheny Power, Commonwealth Edison, AEP, DP&L and Dominion-Virginia Power. As a result, capacity prices have significantly declined. The PJM expansions have resulted in an apparent system-wide surplus of capacity, despite the fact that certain regions in PJM-Mid-Atlantic are currently in need of capacity additions.

On December 22, 2006, the FERC approved, with conditions, a settlement between PJM and multiple market participants regarding PJM s RPM, which was originally filed with the FERC on August 31, 2005, to replace the existing system-wide single clearing price capacity market. The RPM settlement is intended to ensure reliability and reasonable rates in the PJM region. The RPM settlement provides for a three-year forward capacity auction using a modified demand curve from the original RPM filing and locational deliverability zones that will be phased in over several years. Demand curves are administrative mechanisms used to establish electricity generation capacity prices. The RPM settlement will provide increased opportunities for our power plants located in the Mid-Atlantic region to receive more revenues for their capacity. The order approving the RPM is subject to rehearing and a motion to vacate. Parties opposed to the RPM settlement have filed requests with the FERC to rehear, vacate or stay the effectiveness of the December 22, 2006, order, which are currently pending before the FERC.

In addition, PJM and the MISO have been directed by the FERC to establish a common and seamless market, an effort that is largely dependent upon the MISO s ability to first establish and operate its markets. The development of a joint market is contingent on the approval of the internal costs to both entities to develop and operate the infrastructure necessary for joint operations. It is unclear at this time if either the respective entities or the FERC will approve such costs to achieve a common and seamless market.

Northeast Region. Our New York plants participate in a market controlled by the NYISO, which replaced the New York Power Pool. 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 that is similar to that used in PJM and ISO-NE. 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 facilities operate outside of New York City and Long Island. On April 21, 2005, the FERC issued an order accepting the NYISO s demand curves for capability years 2005/2006, 2006/2007 and 2007/2008 with minor modifications to the NYISO s proposal. The new demand curves may result in increased prices within the NYISO for capacity.

Our New England plants 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 effective on February 1, 2005, making ISO-NE responsible for market rule filings at the FERC, in addition to its responsibilities for the operation of transmission systems and administration and settlement of the wholesale electric energy, capacity and ancillary services markets. ISO-NE utilizes a locational marginal pricing model similar to that used in PJM and NYISO. In early 2004, ISO-NE filed with the FERC to adopt a LICAP similar to NYISO s capacity market. After extensive litigation before the FERC on the LICAP proposal, on March 6, 2006, a comprehensive settlement proposal was filed with the FERC between ISO-NE and multiple market participants that would replace the LICAP proposal with a forward capacity market (FCM) under which annual capacity auctions would be conducted for supply three years in advance of delivery. In addition, the settlement provided for a four-year transition period under which capacity suppliers would receive a set price for their capacity commencing on December 1, 2006, and continuing with price escalators through May 31, 2010. On June 16, 2006, the FERC issued a decision accepting the proposed FCM settlement without modification. The FCM will result in increased opportunities for our New England generators to receive more revenues for their capacity commencing in December 2006. The FERC S orders regarding the LICAP and FCM are pending review with the U.S. Court of Appeals. On February 15, 2007, ISO-NE filed the market rules with the FERC to implement FCM. The market rules were supported by a majority of NEPOOL members. NEPOOL did not join in the filing but will be filing separate comments. Existing resources will need to be qualified, and the amount of MW they have to participate in the first auction certified, by April 2007. In June 2007, another round of information will be due from new generators, on a more detailed and binding nature than the show of interest forms. In October, 2007 all resources that want to participate in the first auction will be fully qualified by ISO-NE. The first auction will take place starting February 4, 2008, for the delivery period June 1, 2010 - May 31, 2011.

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 generation output is sold in the real-time market. The CAISO does not operate a forward market like those described for PJM and other Eastern ISO markets, nor does it currently operate a capacity market.

Our subsidiaries owning facilities subject to RMR arrangements are parties to a PPA with PG&E that allows PG&E to dispatch and purchase the power output of all of our CAISO designated RMR units from 2006 through 2012. The PPA currently applies only to Potrero units 3-6, our CAISO designated RMR generating units for 2007. Under the PPA, through 2008 PG&E is paying us charges equivalent to the rates we charged during 2004 when the units were designated RMR Contract Condition 2 reduced by $1.4 million for each year. For 2009 through 2012, the charges for the units that are then subject to the PPA will be determined annually by the FERC.

The CAISO has proposed changes to its market design to more closely mirror the eastern ISO markets, including establishing a wholesale capacity market. The market redesign has been delayed several times, with full implementation now expected in 2008. Any proposal for a capacity market in California is subject to filing with and approval by the FERC, and at this time, the CAISO has not proposed a capacity market mechanism in its market redesign. The CPUC has taken a role in developing recommended options with respect to a wholesale capacity market in conjunction with the CAISO. We cannot at this time predict the outcome of the CPUC proceeding or the timing or structure of a wholesale capacity market in California.

The FERC approved a $400 per MWh cap, effective on January 1, 2006, on prices for energy in the CAISO market, which was an increase from the previous $250 per MWh cap, but still far short of the $1,000 per MWh energy cap utilized in the other FERC approved RTO markets. In addition, owners of non-hydroelectric generation in California, including certain of our facilities, must offer to keep their generation on-line and stand ready to offer power into the CAISO s spot markets if the output is not under contract or scheduled for delivery within the hour, unless granted a waiver by the CAISO. The practical effect of this rule is to obtain operating reserves without paying for them, and to release excess energy into the market, thereby depressing prices. On August 26, 2005, the Independent Energy Producers, a trade association, filed a complaint with the FERC, requesting that the FERC require the CAISO to implement a reliability capacity services tariff (RCST) that would pay generators for the capacity obtained pursuant to the must-offer requirement. Prior to the FERC s ruling on the merits of the complaint, the CAISO and multiple market participants filed a settlement that would implement a form of the RCST. On February 13, 2007, the FERC approved the RCST settlement with minor modifications with an effective date of June 1, 2006. The RCST settlement may result in increased capacity revenue opportunities for generators and possibly could increase revenues for certain units at our Pittsburg and Contra Costa plants for the June 1 - December 31, 2006, period, depending upon how the CAISO implements the terms of the settlement. However, after December 31, 2006, our Pittsburg and Contra Costa plants are under contract for varying periods from now until 2011, and we will not realize any opportunities from RCST until those contracts expire.

The CPUC has issued a series of orders purporting to require exempt wholesale generators and other power plant owners to comply with detailed operation, maintenance and recordkeeping standards for electricity generating facilities. In its orders, the CPUC has stated its intent to implement and enforce these detailed standards to maintain and protect the public health and safety of California residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy. The CPUC has adopted detailed reporting requirements for the standards, and conducts frequent on-site spot inspections and more comprehensive facility audits to evaluate compliance. Some standards are intended to ensure that units are maintained in a state of readiness so as to be available to operate if requested by a control area operator, while others provide procedures for changing a unit s long-term status. The CPUC s efforts to implement and enforce the operation, maintenance and recordkeeping standards could interfere with our future ability to make economic business decisions regarding our units, including decisions regarding unit retirements, and could have a material adverse impact on our business activities in California.

Environmental Regulation

Our business is subject to extensive environmental regulation by federal, state and local authorities. This requires us to comply with applicable laws and regulations, and to obtain and comply with the terms of government issued permits. Our costs of complying with environmental laws, regulations and permits are substantial. We expect that cash flows from operations will be sufficient to fund these capital expenditures.

Maryland Healthy Air Act. On August 3, 2006, we announced a plan to comply with the requirements of the Maryland Healthy Air Act by reducing SO2 emissions by as much as 95% at our Maryland power plants. We will install flue gas desulphurization (FGD) emissions controls at our Chalk Point, Dickerson and Morgantown plants. In addition, we will install selective catalytic reduction (SCR) systems at the Morgantown (as contemplated by the pending NOx Consent Decree described in Item 3. Legal Proceedings, Environmental Matters) and Chalk Point facilities that will reduce NOx emissions by approximately 80%. Together, the FGDs and the SCRs will reduce by approximately 80% the emissions of ionic mercury from the three Maryland power plants.

The Maryland Healthy Air Act requires deeper reductions in NOx and SO2 in 2010 and 2015 than reductions required under federal law including the CAIR. As a result of passage of the more restrictive Maryland state standard on NOx and SO2 emissions, our plan to install control equipment will allow the Maryland facilities to meet or exceed the CAIR limits. We anticipate that the capital expenditures to achieve compliance for SO2 and NOx emissions will be approximately $1.6 billion through 2009. The Maryland Healthy Air Act also requires reductions of mercury emissions by the year 2010. As a result of our installation of equipment to satisfy the more restrictive Maryland state standard on mercury emissions, our Mid-Atlantic facilities will also meet or exceed the CAMR limits. The state law also requires Maryland to join the Regional Greenhouse Gas Initiative (RGGI), a seven state plan to reduce CO2 emissions by 2018. The State of Maryland will initiate a rule-making proceeding in 2007 to determine the regulatory framework for RGGI participation.

At the federal level, there are efforts to pass legislation to mandate reductions of CO2 emissions from generation facilities. There are several pieces of legislation being advanced that vary in levels of reductions and mechanisms for compliance.

Air Emissions Regulations. Our most significant environmental requirements in the United States generally fall under the Clean Air Act 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. Several of our facilities are located in or near metropolitan areas, such as New York City, Boston, San Francisco and Washington D.C., which are classified by the EPA as not achieving certain NAAQS. As a result of the NAAQS classification of these areas, our operations are subject to more stringent air pollution requirements, including, in some cases, further emissions reductions. In the future, we anticipate increased regulation of generation facilities under the Clean Air Act and applicable state laws and regulations concerning air quality. Significant air regulatory programs to which we are subject include those described below.

Clean Air Interstate Rule (CAIR). In May 2005, the EPA promulgated the CAIR regulations, which established in the eastern United States an SO2 and NOx cap-and-allowance trading program applicable to generation facilities. These cap-and-trade programs will be implemented in two phases, with the first phase going into effect in 2010 and more stringent caps going into effect in 2015. In order to comply with the first phase of those regulations, we will have to install additional pollution control equipment and/or purchase additional emissions allowances, at significant cost. We are planning to install pollution control equipment at some of our facilities to address, in part, our requirements under the first phase of the CAIR. The costs of that equipment are included in our estimate of anticipated environmental capital expenditures from 2007 through 2010. However, since the determination of how much pollution control equipment to install is based upon factors such as the cost of emissions allowances and the operational demands on our generation facilities, our plans may change significantly. For our Maryland facilities, compliance with the Maryland Healthy Air Act meets or exceeds the requirements under CAIR.

Clean Air Mercury Rule (CAMR). In May 2005, the EPA issued the CAMR, which limits total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program. The first phase begins in 2010 and the second phase begins in 2018. The EPA expects that, in the first stage, the necessary reductions in mercury will be achieved as a co-benefit using the same pollution control equipment required to achieve the reductions of SO2 and NOx under the CAIR. All states are required to adopt either the EPA rule or a state rule meeting the minimum requirements outlined in the CAMR. Under the EPA rule, we will receive an allocation of mercury emissions allowances associated with our coal-fired plants nationwide, unless there are restrictions imposed at the state level. We expect our coal-fired facilities to comply with the CAMR regulations by taking advantage of the co-benefits derived from NOx and SO2 controls that are, or will soon be, installed.

NSR enforcement initiative. In 1999, the DOJ, on behalf of the EPA, commenced enforcement actions against a number of companies in the power generation industry for alleged violations of the NSR regulations, which require permitting and impose other requirements for certain maintenance, repairs and replacement work on facilities. These enforcement actions can result in a facility owner having obligations to, among other things, install emissions controls at significant cost. These enforcement actions were broadly challenged by the industry in the courts, among other reasons, for being a new interpretation of longstanding regulations. In an effort to provide additional clarity, it is expected that in 2007 the Bush administration will adopt new air pollution rules to clarify what constitutes an emissions increase under the NSR program.

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 plants. If a violation is determined to have occurred at any of the plants, our subsidiary owning or leasing the plant 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 plants in Maryland will be installing a variety of emissions control equipment on those plants to comply with the Maryland Healthy Air Act, but that equipment may not include all of the emissions control equipment that would be required if a violation of the EPA s NSR regulations is determined to have occurred at one or more of those plants. If such a violation is determined to have occurred after our subsidiaries acquired or leased the plants or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, our subsidiary owning or leasing the plant 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 plant, 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 plants.

State air regulations. Various states where we do business also have other air quality laws and regulations with increasingly stringent limitations and requirements that will become applicable in future years to our facilities and operations. We expect to incur additional compliance costs as a result of these additional state requirements, which could include significant expenditures on emissions controls or have other impacts on operations. Specific state items include:

Virginia CAIR and CAMR Implementation. In April 2006, Virginia enacted the Clean Smokestacks Law, which granted the Virginia State Air Pollution Control Board the discretion to limit the ability of a facility in a non-attainment area to purchase additional mercury, SO2 and NOx allowances to achieve compliance with CAIR and CAMR. The State Air Pollution Control Board has approved the implementing regulations to the Clean Smokestacks Law but they have not yet been promulgated. The State Air Pollution Control Board has interpreted the current form of these regulations as restricting facilities in non-attainment areas from purchasing emission allowances to achieve compliance with CAIR and CAMR. If the regulations are promulgated in their current form and the State Air Pollution Control Board s interpretation is correct, such restrictions would reduce our flexibility in complying with CAIR and CAMR and could result in operating restrictions for our Potomac River generating facility in Virginia.

Massachusetts Emissions Standards for Power Plants. The Commonwealth of Massachusetts has finalized regulations to further reduce NOx emissions from certain generation facilities. The Massachusetts regulations relate to NOx emissions during ozone season and become effective in 2009. Our operations will not be materially affected by the newly established limits.

New York. 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. On June 11, 2003, Mirant New York, Mirant Lovett and the State of New York entered into 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 has three options: (1) install emissions controls on Lovett s two coal-fired units; (2) shut down one unit and convert one unit to natural gas; or (3) shut down both coal burning units in 2007 and 2008. If Mirant Lovett elects to install emissions controls on its two coal-fired units by 2007 through 2008, it must install: (a) emissions controls consisting of SCR technology to reduce NOx emissions; (b) alkaline in-duct injection technology to reduce SO2 emissions; and (c) a baghouse. Additionally, in 2003, the State of New York finalized air regulations that significantly reduced allowances for NOx and SO2 emissions from generation facilities through a state emissions cap-and-trade program, which will become effective during the 2006-2008 timeframe.

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. The 2003 Consent Decree imposes similar requirements with respect to unit 4 that have to be met by April 30, 2008.

Climate change. Concern over climate change has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

In 1998, the United States became a signatory to the Kyoto Protocol of the United Nations Framework Convention on Climate Change. The Kyoto Protocol, which became effective in February 2005 after Russia s ratification in November 2004, calls for developed nations to reduce their emissions of greenhouse gases to 5% below 1990 levels by 2012. CO2, which is a major byproduct of the combustion of fossil fuel, is a greenhouse gas that would be regulated under the Kyoto Protocol. The United States Senate indicated that it would not enact the Kyoto Protocol, and in 2002 President Bush confirmed that the United States would not enter into the Kyoto Protocol. Instead, the President indicated that the United States would support voluntary measures for reducing greenhouse gases and technologies that would use or dispose of CO2 effectively and economically. As the Kyoto Protocol becomes effective in other countries, there is increasing pressure for sources in the United States to be subject to mandatory

restrictions on CO_2 emissions. In the last year, the United States Congress has considered bills that would regulate domestic greenhouse gas emissions, but such bills have not received sufficient Congressional approval to date to become law. If the United States ultimately ratifies the Kyoto Protocol and/or if the United States Congress or individual states or groups of states in which we operate ultimately pass legislation regulating the emissions of greenhouse gases such as the RGGI discussed below, any resulting limitations on generation facility CO_2 emissions could have a material adverse impact on all fossil fuel- fired generation facilities (particularly coal-fired facilities), including ours.

On August 16, 2006, a model rule was finalized and seven states in the Northeast will move forward with the implementation of the RGGI. This is a multi-state regional initiative that uses a regional cap-and-trade program to reduce CO_2 emissions from power plants of 25 MW or greater. The program aims to stabilize CO_2 emissions to current levels from 2009 to 2015. This is to be followed by a 10% reduction in emissions by 2019. At this time, our assets in Maryland, Massachusetts and New York will be affected, and we are evaluating our options to comply with the requirements of the rule.

In addition, separate from the RGGI, California and Massachusetts have also enacted limitations on CO_2 emissions from power plants which affect our gas-fired plants in California and our Canal facility in Massachusetts. We expect that we will be able to comply with these restrictions either by reducing our emissions or purchasing emissions credits if permitted by the applicable law, but if we are unable to comply, we will be forced to curtail our operations at these facilities.

At the federal level Congress is expected to advance several mandatory CO_2 bills, which may require reductions of CO_2 emissions nationwide.

Water regulations. We are required under the Clean Water Act to comply with effluent and intake requirements, technological controls requirements and operating practices. Our wastewater discharges are subject to permitting under the Clean Water Act, and our permits under the Clean Water Act are subject to review every five years. As with air quality regulations, federal and state water regulations are expected to increase and impose additional and more stringent requirements or limitations in the future. This is particularly true for regulatory requirements governing cooling water intake structures, which are subject to regulation under section 316(b) of the Clean Water Act. A recent decision by the United States Court of Appeals for the Second Circuit in *Riverkeeper Inc. et al v. EPA*, in which the court remanded numerous provisions of the EPA s current 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. Until the EPA acts on the issues remanded, it is impossible to say exactly what requirements will be imposed or what they will cost.

In February 2006, Mirant Delta received correspondence from the U.S. Fish and Wildlife Service and the U.S. Army Corps of Engineers expressing the view that the federal Endangered Species Act coverage for our Contra Costa and Pittsburg facilities located along the Sacramento River and Suisun Bay is insufficient or inoperative. Endangered Species Act consultation has been formally reinitiated, and we are continuing to work with these agencies to resolve these issues. It is possible, however, that we will be unable to resolve these issues with the agencies and that more formal legal action may be instituted against us resulting in substantial fines or operational curtailment of these facilities.

On May 10, 2006, the San Francisco Regional Water Quality Control Board issued Mirant Potrero a National Pollution Discharge Elimination System permit pursuant to the Clean Water Act regulating the Potrero facility s cooling water and process water discharges to the San Francisco Bay. Communities for a Better Environment, an environmental advocacy organization, contested various elements of the permit in a petition filed with the California State Water Resources Control Board on June 8, 2006, seeking relief that could include a plant curtailment, and/or costly technological upgrades. Mirant Potrero filed a timely response to this petition as the permit holder on November 27, 2006, in support of the Regional Board s permit decision. A decision from the State Board is expected by July 2007.

On September 26, 2006, the Massachusetts Department of Environmental Protection and the EPA jointly issued to Mirant Kendall a Surface Water Discharge Permit (SWDP) and a National Pollutant Discharge Elimination System (NPDES) permit for the Kendall generating facility. The new permit imposes in-stream temperature limits, 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 significant portions of the SWDP and NPDES permit, along with a related state Water Quality Certificate. The portions of the permits that Mirant Kendall has appealed are stayed pending appeal. We are unable to predict the outcome of this proceeding.

Wastes, hazardous materials and contamination. Our facilities are subject to several waste management laws and regulations in the United States. The Resource Conservation and Recovery Act of 1976 set forth 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 from these facilities. The EPA may develop new regulations that impose additional requirements on facilities that store or dispose of fossil fuel combustion materials, 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 for increased waste management requirements.

Additionally, CERCLA, or Superfund, establishes a 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. Areas of soil and groundwater contamination are known to exist at our Pittsburg, Contra Costa and Potrero facilities. Prior to our acquisition of those facilities from PG&E in 1998, PG&E conducted soil and groundwater investigations at those facilities which revealed significant 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 at the Potrero generating facility and the disposition of up to 60,000 cubic yards of contaminated soil at the Potrero generating facility and the remediation of any groundwater or solid contamination identified by PG&E at the Pittsburg and Contra Costa generating facilities. Pursuant to our requests, PG&E has disposed of 807 cubic yards of contaminated soil at the Potrero generating facility. We are not aware of soil or groundwater conditions for which we expect our remediation costs to be material that are not covered by third-party agreements.

Employees

At December 31, 2006, our corporate offices and majority owned or controlled subsidiaries employed approximately 4,440 people. This number includes approximately 1,820 employees in the United States, approximately 1,620 employees in the Caribbean, and approximately 1,000 employees in the Philippines. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
Continuing Operations:			
IBEW Local 1900	Maryland and Virginia	482	6/1/2010
IBEW Local 503	New York	136	6/1/2008
IBEW Local 1245	California	123	10/31/2008
UWUA Local 369	Cambridge, Massachusetts	34	2/28/2009
UWUA Local 480	Sandwich, Massachusetts	51	6/1/2011
Total		826	
Discontinued Operations:			
IBEW Local 396	Nevada	18	7/28/2008
United Steel Workers Local 12502(1)	Indiana and Michigan	27	1/1/2007
Bahamas Industrial Engineers, Managerial, and Supervisory Union(2)	Grand Bahama	36	1/1/2005
Commonwealth Electrical Workers Union(3)	Grand Bahama	135	3/31/2005
Jamaica Public Service Managers Association	Jamaica	165	11/30/2007
Union of Clerical Administrative & Supervisory Employees; National Workers Union; Bustamante Industrial Trade Union	Jamaica	1,057	12/31/2007
Petroleum Workers Federation of Curacao(4)	Curacao	37	
Total		1,475	

(1) One year contract extension through 1/1/2008.

(2) Union negotiations are at a stalemate. Overall, the industrial climate is stable.

(3) Negotiations are ongoing.

(4) Initial contract under negotiation.

To mitigate and reduce the risk of disruption during labor negotiations, we engage in contingency planning for continuation of our generation and/or distribution activities to the extent possible during an adverse collective action by one or more of our unions. If our non-unionized workforce moved toward unionization, we could be materially affected through increased employee costs, work stoppages or both.

Item 1A *Risk Factors*

The following are factors that could affect our future performance:

Our revenues are unpredictable because many 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 many of our generating facilities into competitive power markets on a short-term fixed price basis or through power sales agreements. 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, the marginal and long run costs incurred by our competitors and the impact of market regulation. Lack of diversification in revenue may also result in concentrated exposure to markets, especially PJM. The price for which we can sell our output may fluctuate on a day-to-day basis. 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, limiting 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 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 sufficient for recovery of our costs, our investment and an adequate return on our investment;

- 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, refusal by regulators to allow utilities to fully recover their wholesale power costs and investments through rates, catastrophic losses and losses from investments in unregulated businesses;

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

- increases in supplies due to actions of our current competitors or new market entrants, including the development of new generating facilities 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;

- 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;

- weather conditions that depress demand or increase the supply of hydro power; and

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

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.

27

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, and we may be unsuccessful at managing this risk.

Our generation business is subject to changes in power prices and fuel costs, which 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. In addition, actual power prices and fuel costs may differ from our expectations.

Mirant Energy Trading engages in asset management activities related to sales of electricity and purchases of fuel. The income and losses from these activities are recorded as generation revenues and fuel costs. Mirant Energy Trading may use forward contracts and derivative financial instruments to manage market risk and exposure to volatility in electricity, coal, natural gas, emissions and oil prices. 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 and fuel markets.

Many factors influence commodity prices, including weather, market liquidity, transmission and transportation inefficiencies, availability of competitively priced alternative energy sources, demand for energy commodities, natural gas, crude oil and coal production, natural disasters, wars, embargoes and other catastrophic events, and federal, state and foreign energy and environmental regulation and legislation.

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. As a result of these and other factors, we cannot predict the impact that risk management decisions may have on our businesses, operating results or financial position. Although management devotes a considerable amount of 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 natural gas, coal and oil fuel supply.

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.

Some of our generation facilities depend on only one or a few customers or suppliers. These parties, as well as other parties with whom we have contracts, may fail to perform their obligations, or may terminate their existing agreements, which may result in a default on project debt or a loss in revenues and may require us to institute legal proceedings to enforce the relevant agreements.

Several of our power production facilities depend on a single customer or a few customers to purchase most or all of the facility s output or on a single supplier or a few suppliers to provide fuel, water and other services required for the operation of the facility. The sale and procurement agreements for these facilities may also provide support for any project debt used to finance the facilities. The failure of any supplier or customer to fulfill its contractual obligations to the facility could have a material adverse effect on such facility s financial results. The financial performance of these facilities is dependent on the continued performance by customers and suppliers of their obligations under their long-term agreements.

Revenue received by our subsidiaries may be reduced upon the expiration or termination of existing power sales agreements. Some of the electricity we generate from our existing portfolio is sold under long-term power sales agreements that expire at various times. When the terms of each of these power sales agreements expire, it is possible that the price paid to us for the generation of electricity may be reduced significantly, which would substantially reduce our revenue.

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

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

- the output and efficiency levels at which those generation facilities perform;
- interruptions in fuel supply;
- disruptions in the delivery of electricity;
- adverse zoning;
- breakdowns or equipment failures (whether due to 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;
- shortages of equipment or spare parts;
- labor disputes;
- operator errors;
- curtailment of operations due to transmission constraints;
- failures in the electricity transmission system which may cause large energy blackouts;
- implementation of unproven technologies in connection with environmental improvements; and
- catastrophic events such as fires, explosions, floods, earthquakes, hurricanes or other similar occurrences.

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

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

We engage in asset management activities to economically hedge our exposure to market risk with respect to: (1) electricity sales from our generation 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 contracts. We also use derivative contracts 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 and proprietary trading activities are recorded on our balance sheet at fair value pursuant to

29

SFAS No. 133. None of our derivatives recorded at fair market value are designated as hedges under SFAS No. 133 and changes in their fair value 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 due to changes in forward electricity and fuel prices. For a more detailed discussion of the accounting treatment of our asset management and proprietary trading activities, see Note 7 to our consolidated financial statements, included herein.

Our results are subject to quarterly and seasonal fluctuations.

Our operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including:

- seasonal variations in demand and corresponding energy and fuel prices; and
- variations in levels of production.

We compete to sell energy and capacity 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 generation 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.

Operating in foreign countries involves a number of risks.

Our operations and earnings in the Philippines and Caribbean have been, and may in the future be, affected from time to time in varying degrees by political instability and by other political developments and laws and regulations which may affect both operations and financial affairs, such as forced divestiture of assets or required public offerings of equity interests in those assets; restrictions on production, imports and exports; war or other international conflicts; civil unrest and local security concerns that threaten the safe operation of company facilities; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights; currency fluctuations and environmental regulations. Both the likelihood of such occurrences and their overall effect upon us vary greatly from country to country and are not predictable.

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 operating permits and remain in continuous compliance with the conditions established by those operating permits. To comply with these legal requirements and the terms of our operating 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 and the imposition of liens or fines. In addition, we may be required to shut down facilities if we are unable to comply with the requirements, such as with CO_2 regulations for which there currently is not a technical compliance solution, or if we determine the expenditures required to comply are uneconomic.

In addition, environmental laws, particularly with respect to air emissions, wastewater discharge and cooling water intake structures, are generally becoming more stringent, which may require us to make expensive facility upgrades or restrict our operations to meet more stringent standards. With the trend toward stricter standards, greater regulation, and more extensive permitting requirements, we expect our environmental expenditures to be substantial in the future. Although we have budgeted for significant expenditures to comply with these requirements, actual expenditures may be greater than budgeted amounts. We may have underestimated the cost of the environmental work we are planning or the air emissions allowances we anticipate buying. In addition, new environmental laws may be enacted, new or revised regulations under those laws may be issued, the interpretation of such laws and regulations by regulatory authorities may change, or additional information concerning the way in which such requirements apply to us may be identified. For example, in April 2006, Maryland enacted the Healthy Air Act, which requires more significant reductions in emissions of NOx, SO2 and mercury than the recently finalized CAIR and CAMR. This legislation affects our Chalk Point, Dickerson and Morgantown facilities. We anticipate that the capital expenditures to achieve compliance for SO2 and NOx emissions will be approximately $1.6 billion through 2009.

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 any environmental regulatory approvals or if onerous conditions are imposed, the operation of our generation facilities 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.

Certain environmental laws, including CERCLA and comparable state laws, impose strict and, in many circumstances, joint and several liability for costs of 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 generation 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 generation facilities, at disposal sites we currently utilize or have formerly utilized, 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. In the event that 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 additional emissions allowances to meet the mandated levels. To meet these requirements, we plan to install scrubbers on all of our Maryland coal facilities. We may not meet this construction schedule by January 2010 due to a number of factors, which may result in a loss of cash flows from operations due to reduced unit operations.

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

We expect that certain of our generation facilities and related properties will become subject to decommissioning and/or site remediation obligations that may require material expenditures. The exact amount and timing of such expenditures, if any, is not presently known. 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 level of 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 our obligations.

As of December 31, 2006, our total indebtedness for continuing operations was approximately $3.3 billion. In addition, the present value of lease payments under the Mirant Mid-Atlantic leveraged leases is approximately $1.1 billion (assuming a 10% discount rate) and the termination value of the Mirant Mid-Atlantic leveraged leases is $1.4 billion. Our substantial degree of leverage 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 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 (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 holding company subsidiaries, 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 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 United States 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 us. Mirant Mid-Atlantic s ability to satisfy the criteria set by that covenant in the future could be impaired by factors which negatively affect the performance of its power generation facilities, including interruptions in operation or curtailment of operations to comply with environmental restrictions.

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, except to the extent that such obligations or indebtedness are assumed or guaranteed by a subsidiary.

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

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 generation 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, 2006, we had approximately $227 million of posted cash collateral and $260 million of letters of credit outstanding primarily to support our asset management activities and debt service reserve requirements. 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.

If our facilities experience unplanned outages, we may be required to procure replacement power in the open market to satisfy contractual commitments. Without 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.

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 cost impacts, in turn, may negatively affect our financial condition and results of operations.

Generally, in the United States, 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 generation 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 generation 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 assets are subject to rules and terms of participation imposed and administered by various RTOs and ISOs. 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 and capacity.

Changes in the markets in which we compete may have an adverse impact on the results of our operations. For example, in the fall of 2004, PJM completed its integration of AEP, Duquesne Light and DP&L into PJM. Under PJM rules, AEP, Duquesne Light and DP&L were then deemed by PJM to be capable of providing capacity to all areas of PJM. The integration of these companies into PJM in conjunction with the existing market rules depressed the prices that can be charged for capacity in PJM.

To conduct our business, we must obtain 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.

On August 8, 2005, the EPAct 2005 was enacted. Among other things, the EPAct 2005 provides incentives for various forms of electric generation technologies, which will subsidize certain of our competitors. Many regulations that could be issued pursuant to the EPAct 2005 may have an adverse impact on our business.

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 both to advance and to roll back 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 suffer. 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.

We may be liable for certain underfunded liabilities with respect to pension plans offered by Mirant and its affiliates.

We and our affiliates offer pension benefits to employees through various pension plans. Funding obligations under the U.S. pension plans are governed by the ERISA and some of the plans are underfunded. As of December 31, 2006, our U.S. pension plans had an underfunded accumulated benefit obligation of approximately $59 million, and an underfunded projected benefit obligation of approximately $102 million, in aggregate as calculated in accordance with SFAS No. 158. As of December 31, 2006, our non-U.S. pension plans were overfunded on an accumulated benefit obligation basis by approximately $78 million, and on a projected benefit obligation basis by approximately $54 million, in the aggregate, as calculated in accordance with SFAS No. 158. Unless the underfunded liabilities are eliminated through asset returns, rising interest rates or other gains exceeding plan assumptions, we and our affiliates will have to satisfy the underfunded amounts of these plans through cash contributions over time. The timing and amounts of funding requirements depend upon a number of factors, including interest rates, asset returns, potential changes in pension legislation, our decision to make voluntary prepayments, applications for and receipt of waivers to reschedule contributions and changes to pension plan benefits.

The Pension Protection Act was enacted on August 17, 2006. While the Pension Protection Act will have some effect on specific plan provisions in our retirement programs, the primary effect will be to change the minimum funding requirements for plan years beginning in 2008. The Pension Protection Act has directed the United States Department of the Treasury to develop a new yield curve to discount pension obligations for determining the funded status of a plan when calculating funding requirements. Until regulations are issued by the Department of the Treasury, we are unable to determine the effect on our consolidated financial statements; however, such regulations are unlikely to have a material adverse effect on our results of operations.

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

A basic premise of our generation business is that generating power at central facilities achieves economies of scale and produces electricity at a low price. There are other technologies that can produce electricity, most notably fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technology will reduce the cost of alternative methods of electricity production to levels that are equal to or below that of most central station electric production, which could have a material impact on our results of operations.

Terrorist attacks, future war 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 generation facilities or an inability to operate as a result of systemic damage resulting from an act against the transmission and distribution infrastructure that we use to transport our power. If such an attack were to occur, our business, financial condition and results of operations 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 generation industry. We may not have adequate insurance to cover all of these hazards.

Our operations are subject to many hazards associated with the power generation 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, 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.

The subsidiaries that own our generation facilities in New York, including our Lovett and Bowline facilities, have not emerged from Chapter 11.

Our subsidiaries related to our New York business operations, Mirant New York, Mirant Bowline, Mirant Lovett, Hudson Valley Gas and Mirant NY-Gen, remain in bankruptcy. Our Lovett and Bowline generation facilities in New York were subject to disputes with local tax authorities regarding property tax assessments that were not resolved until December 2006. Mirant Lovett is in discussions with the NYSDEC and the New York State Office of the Attorney General regarding environmental controls required under the 2003 Consent Decree for the Lovett generation facility to continue operating past April 30, 2007, for unit 5 and past April 2008, with respect to unit 4. Until a resolution is reached on environmental controls that would permit economically feasible operation, Mirant Lovett will likely remain in Chapter 11. Mirant NY-Gen, which owns hydroelectric facilities at Swinging Bridge, Rio and Mongaup, and small combustion turbine facilities at Hillburn and Shoemaker, is insolvent. Its expenses are being funded under a debtor-in-possession facility provided by Mirant Americas with the approval of, and under the supervision of, the Bankruptcy Court. Mirant NY-Gen is proceeding with the implementation of a remediation plan for the sinkhole discovered in May 2005 in the dam at the Swinging Bridge facility.

On January 26, 2007, the Emerging New York Entities filed the Supplemental Plan with the Bankruptcy Court. For more information on the Supplemental Plan, see Item 3. Legal Proceedings, Chapter 11 Proceedings. The hearing before the Bankruptcy Court to consider the confirmation of the Supplemental Plan is scheduled for March 21, 2007. Until our subsidiaries related to our New York business operations emerge from bankruptcy, we will not have access to the cash from operations generated from these subsidiaries. In 2006, our New York operations generated $17 million of cash from operating activities.

On January 31, 2007, Mirant New York entered into an agreement for the sale of Mirant NY-Gen, which owns the Hillburn and Shoemaker gas turbine facilities and the Swinging Bridge, Rio and Mongaup hydroelectric generating facilities. An auction process supervised by the Bankruptcy Court is required before bankruptcy court approval may occur. The estimated sales price of $3 million is subject to adjustments for working capital and certain dam remediation efforts that are ongoing at the Swinging Bridge facility. The transaction is expected to close in the second quarter of 2007.

We may be subject to claims that were not discharged in the bankruptcy cases, which could have a material adverse effect on our results of operations and profitability.

The nature of our business frequently subjects us to litigation. Substantially all of the material claims against us that arose prior to the bankruptcy filing in July 2003 were resolved during our Chapter 11 proceedings. In addition, the Bankruptcy Code provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation and certain debts arising afterwards. With a few exceptions, all claims that arose prior to our bankruptcy filing and before confirmation of the Plan in December 2005 are (1) subject to compromise and/or treatment under the Plan or (2) discharged, in accordance with the Bankruptcy Code and terms of the Plan. Circumstances in which claims and other obligations that arose prior to our bankruptcy filing were not discharged primarily relate to certain actions by governmental units under police power authority, where we have agreed to preserve a claimant s claims, as well as, potentially, instances where a claimant had inadequate notice of the bankruptcy filing. The ultimate resolution of such claims and other obligations may have a material adverse effect on our results of operations and profitability.

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 vigorously defend 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.

Item 2. *Properties*

The following properties were owned or leased as of December 31, 2006:

Operating Plants:

Power Generation Business	Location	Plant Type	Primary Fuel	Mirant s % Leasehold/ Ownership Interest(1)	Total MW(2)	Net Equity Interest/ Lease in Total MW(2)	2006 Capacity Factor(3)
Continuing Operations							
Mid-Atlantic Region:							
Chalk Point	Maryland	Intermediate/Baseload/Peaking	Natural Gas/Coal/Oil	100	2,429	2,429	22 %
Dickerson	Maryland	Baseload/Peaking	Natural Gas/Coal/Oil	100	853	853	42 %
Morgantown	Maryland	Baseload/Peaking	Coal/Oil	100	1,492	1,492	58 %
Potomac River	Virginia	Intermediate/Baseload	Coal	100	482	482	26 %
Total Mid-Atlantic					5,256	5,256	36 %
Northeast Region:							
Canal	Massachusetts	Intermediate	Natural Gas/Oil	100	1,112	1,112	17 %
Kendall	Massachusetts	Baseload	Natural Gas/Oil/Jet fuel	100	256	256	52 %
Martha s Vineyard	Massachusetts	Peaking	Diesel	100	14	14	1 %
Wyman	Maine	Peaking	Fuel Oil	1.4	614	9	
Total New England					1,996	1,391	23 %
Bowline	New York	Intermediate/Peaking	Natural Gas/Oil	100	1,125	1,125	2 %
Hillburn	New York	Baseload/Peaking	Natural Gas/Jet Fuel	100	51	51	
Lovett	New York	Baseload/Peaking	Natural Gas/Coal/Oil	100	411	411	44 %
Mongaup	New York	Intermediate/Peaking	Hydro	100	4	4	23 %
Rio	New York	Intermediate/Peaking	Hydro	100	9	9	34 %
Shoemaker	New York	Peaking	Natural Gas/Jet Fuel	100	44	44	1 %
Swinging Bridge	New York	Intermediate/Peaking	Hydro	100	12	12	8 %
Total New York				100	1,656	1,656	13 %
Total Northeast					3,652	3,047	17 %
California:							
Contra Costa	California	Intermediate	Natural Gas	100	674	674	2 %
Pittsburg	California	Intermediate	Natural Gas	100	1,311	1,311	4 %
Potrero	California	Intermediate/Peaking	Natural Gas/Oil	100	362	362	17 %
Total California					2,347	2,347	6 %
Total Continuing Operations					11,255	10,650	
Discontinued Operations							
Philippines:							
Sual	Philippines	Baseload	Coal	100	1,218	1,218	23 %
Ilijan	Philippines	Baseload	Natural Gas	20	1,251	250	
Pagbilao	Philippines	Baseload	Coal	100	735	735	49 %
Total Philippines					3,204	2,203	33 %
Caribbean:							
PowerGen(4)	Trinidad and Tobago	Intermediate/Peaking/Baseload	Natural Gas	39	1,157	451	55 %
Jamaica Public Service Company Limited	Jamaica	Intermediate/Baseload/Peaking	Oil/Hydro	80	603	482	51 %
Grand Bahama Power	Bahamas	Peaking/Intermediate/Baseload	Oil	55.4	151	83	34 %
CUC	Netherlands Antilles	Baseload/Peaking	Pitch/Refinery Gas	25.5	153	34	
Total Caribbean					2,064	1,050	52 %
U.S. Gas Assets:							
Zeeland	Michigan	Intermediate/Peaking	Natural Gas	100	903	903	6 %
West Georgia	Georgia	Peaking	Natural Gas/Oil	100	613	613	3 %
Sugar Creek	Indiana	Peaking	Natural Gas	100	561	561	4 %
Shady Hills	Florida	Peaking	Natural Gas	100	469	469	8 %
Bosque	Texas	Baseload/Peaking	Natural Gas	100	546	546	28 %
Apex	Nevada	Intermediate	Natural Gas	100	527	527	39 %

Total U.S. Gas Assets	3,619	3,619	13 %
Total Discontinued Operations	8,887	6,872	
Total Mirant	20,142	17,522	

Distribution Business Discontinued Operations	Location	Mirant s % Ownership Interest	Customers/ end-users (in thousands)
Grand Bahama Power	Bahamas	55.4	19
Jamaica Public Service Company Limited	Jamaica	80.0	571
Total			590

(1) Amounts reflect our percentage economic interest in the total MW.

(2) MW amounts reflect net dependable capacity.

(3) Capacity factor is the average percentage of full capacity used over a year.

(4) In addition, on December 6, 2005, PowerGen and T&TEC executed a 30-year 208 MW power sales agreement. On February 23, 2006, PowerGen began construction of an expansion at the Point Lisas generating facility and estimates a commercial operations date of March 2007.

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*

Chapter 11 Proceedings

On July 14, 2003, and various dates thereafter, Mirant Corporation and certain of its subsidiaries (collectively, the Mirant Debtors) filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. Most of the material claims filed against the Mirant Debtors estates were disallowed or were resolved and became allowed claims before confirmation of the Plan that became effective for Mirant and most of the Mirant Debtors on January 3, 2006. Mirant, as the distribution agent under the Plan, has made distributions pursuant to the terms of the Plan on those allowed claims. Some claims, however, remain unresolved.

As of December 31, 2006, approximately 21 million 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 not been resolved. A settlement entered into on May 30, 2006, among Pepco, Mirant, MC 2005, LLC f/k/a Mirant Corporation (Old Mirant), and various subsidiaries of Mirant, if approved by final order in the Chapter 11 proceedings, would result in the distribution of up to 18 million of the reserved shares to Pepco, as described below in *Pepco Litigation*. Under the terms of the Plan, to the extent other such unresolved claims are resolved now that we have emerged from bankruptcy, the claimants will be paid from the reserved shares on the same basis as if they had been paid when the Plan became effective. That means that their allowed claims will receive the same pro rata distributions of Mirant common stock, cash, or both common stock and cash as previously allowed claims in accordance with the terms of the Plan. To the extent the aggregate amount of the payouts determined to be due with respect to such disputed claims ultimately exceeds the amount of the funded claim reserve, Mirant would have to issue additional shares of common stock to address the shortfall, which would dilute existing Mirant shareholders, and Mirant and Mirant Americas Generation would have to pay additional cash amounts as necessary under the terms of the Plan to satisfy such pre-petition claims. If we are required to issue additional shares of common stock to satisfy unresolved claims, certain parties who under the Plan received common stock and warrants also are entitled to receive additional shares of common stock to avoid dilution of their distributions under the Plan.

Our subsidiaries related to our New York business operations, Mirant New York, Mirant Bowline, Mirant Lovett, Hudson Valley Gas and Mirant NY-Gen, remain in bankruptcy. Our Lovett and Bowline generation facilities in New York were subject to disputes with local tax authorities regarding property tax assessments that were not resolved until December 2006, as described below in *New York Tax Proceedings*. Resolution of those tax disputes should allow Mirant New York, Mirant Bowline, and Hudson Valley Gas to emerge from bankruptcy in 2007. On January 26, 2007, Mirant New York, Mirant Bowline, and Hudson Valley Gas (collectively the Emerging New York Entities) filed a Supplemental Joint Chapter 11 Plan of Reorganization of the Emerging New York Entities (the Supplemental Plan) with the Bankruptcy Court. The Supplemental Plan has two main components. First, the Supplemental Plan incorporates a settlement with the various New York tax jurisdictions that resolved the tax disputes related to the Lovett and Bowline facilities. Second, the Supplemental Plan provides unsecured creditors of the Emerging New York Entities with the same treatment afforded holders of unsecured claims against Mirant Americas Generation and its subsidiaries under the Plan. Such unsecured creditors of the Emerging New York Entities will receive their pro rata share of the pool of assets created under the Plan for the benefit of the unsecured creditors of Mirant Americas Generation and its subsidiaries. On January 26, 2007, the Emerging New York Entities also filed a motion with the Bankruptcy Court to establish procedures to facilitate the consideration and confirmation of the Supplemental Plan. That motion requests, among other things, that the Bankruptcy Court find that the Supplemental Plan does not alter in any respect from the Plan the treatment of the holders of unsecured claims against the Emerging New York Entities, and that all votes previously cast by such holders in respect of the Plan (which votes accepted the Plan for the Emerging New York Entities by the requisite number and amount required by the Bankruptcy Code) should be deemed votes cast in respect of the Supplemental Plan. The hearing before the Bankruptcy Court to consider the confirmation of the Supplemental Plan is scheduled for March 21, 2007.

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. The discontinuance of operations at unit 5 is in accordance with the requirements of a June 11, 2003, Consent Decree (the 2003 Consent Decree) among Mirant Lovett, the State of New York and the NYSDEC that requires Mirant Lovett to install certain environmental controls on unit 5 of the Lovett facility or shut down that unit by April 30, 2007. The 2003 Consent Decree imposes similar requirements with respect to unit 4 that have to be met by April 30, 2008. Operations at unit 3 are being discontinued because it is uneconomic to continue to run unit 3 if operations at unit 5 are discontinued. Mirant Lovett is in discussions with the NYSDEC and the New York State Office of the Attorney General regarding environmental controls. If Mirant Lovett is able to agree with the New York Attorney General s office and the NYSDEC on alternative control technologies that would allow unit 5 to remain in operation past April 30, 2007, then Mirant Lovett may rescind the notice of its intent to discontinue operations at units 3 and 5. Until a resolution is reached on environmental controls that would permit economically feasible operation, Mirant Lovett will likely remain in Chapter 11. Mirant NY-Gen, which owns hydroelectric facilities at Swinging Bridge, Rio and Mongaup, and small combustion turbine facilities at Hillburn and Shoemaker, is insolvent. Its expenses are being funded under a debtor-in-possession facility provided by Mirant Americas with the approval of, and under the supervision of, the Bankruptcy Court. Mirant NY-Gen is proceeding with the implementation of a remediation plan for the sinkhole discovered in May 2005 in the dam at the Swinging Bridge facility. The status of the remediation effort is discussed in Other Contingencies in Note 23 to the consolidated financial statements.

On January 31, 2007, Mirant New York entered into an agreement for the sale of Mirant NY-Gen, which owns the Hillburn and Shoemaker gas turbine facilities and the Swinging Bridge, Rio and Mongaup hydroelectric generating facilities. An auction process supervised by the Bankruptcy Court is required before bankruptcy court approval may occur. The estimated sales price of $3 million is subject to adjustments for working capital and certain dam remediation efforts that are ongoing at the Swinging Bridge facility. The transaction is expected to close in the second quarter of 2007.

Until our subsidiaries related to our New York business operations emerge from bankruptcy, we will not have access to the cash from operations generated from these subsidiaries. In 2006, our New York operations generated $17 million of cash from operating activities.

Pepco Litigation

In 2000, Mirant purchased power generating facilities and other assets from Pepco, including certain PPAs between Pepco and third parties. Under the terms of the APSA, Mirant and Pepco entered into a contractual agreement (the Back-to-Back Agreement) with respect to certain PPAs, including Pepco s long-term PPA with Panda, under which (1) Pepco agreed to resell to Mirant all capacity, energy, ancillary services and other benefits to which it is entitled under those agreements and (2) Mirant agreed to pay Pepco each month all amounts due from Pepco to the sellers under those agreements for the immediately preceding month associated with such capacity, energy, ancillary services and other benefits. The Panda PPA runs until 2021, and the Back-to-Back Agreement does not expire until all obligations have been performed under the Panda PPA. Under the Back-to-Back Agreement, Mirant is obligated to purchase power from Pepco at prices that typically are higher than the market prices for power.

Pepco Contract Litigation. On August 28, 2003, the Mirant Debtors filed a motion in the bankruptcy proceedings to reject the Back-to-Back Agreement (the First Rejection Motion). If the Mirant Debtors succeed in rejecting the Back-to-Back Agreement, Mirant would have no further obligations with respect to that agreement and Pepco would receive a claim in the bankruptcy proceedings for its resulting

40

damages. On December 9, 2004, the United States District Court for the Northern District of Texas held that the Back-to-Back Agreement was a part of and not severable from, and therefore could not be rejected apart from, the APSA. The Mirant Debtors appealed that decision to the United States Court of Appeals for the Fifth Circuit (the Fifth Circuit). On July 19, 2006, the Fifth Circuit affirmed the district court s December 9, 2004, decision, concluding that the APSA, the Back-to-Back Agreement and other agreements executed under the terms of the APSA constituted a single agreement and that the Back-to-Back Agreement could not be separately rejected.

On January 21, 2005, the Mirant Debtors filed a separate motion in the bankruptcy proceedings to reject the APSA, including the Back-to-Back Agreement but not including other agreements entered into between Mirant and its subsidiaries and Pepco under the terms of the APSA (the Second Rejection Motion). On August 16, 2005, the district court informally stayed the Second Rejection Motion pending rulings by the Fifth Circuit on the Mirant Debtors appeals from the district court s December 9, 2004, decision denying the First Rejection Motion. On January 31, 2007, the district court terminated this proceeding based on the filing of the proposed settlement described below in Proposed Pepco Settlement.

On December 1, 2005, the Mirant Debtors filed a complaint with the Bankruptcy Court seeking to recharacterize the Back-to-Back Agreement as a debt obligation arising prior to the filing of the Chapter 11 proceedings (the Recharacterization Complaint). The complaint seeks the recovery of all payments made to Pepco under the Back-to-Back Agreement since the filing of the Chapter 11 proceedings. If the Mirant Debtors succeed on the Recharacterization Complaint, Pepco would receive a claim in the bankruptcy proceedings for the amount of any payments recovered by the Mirant Debtors and for the amount owed under the Back-to-Back Agreement for its remaining term. The Recharacterization Complaint remains pending in the Bankruptcy Court.

Pending a final determination of the Mirant Debtors ability to reject the APSA, the Back-to-Back Agreement, and certain other agreements with Pepco, and the resolution of the Recharacterization Complaint, the Plan provides that the Mirant Debtors obligations under the APSA and the Back-to-Back Agreement are interim obligations of Mirant Power Purchase and are unconditionally guaranteed by Mirant. If the Mirant Debtors succeed in rejecting or recharacterizing any of these agreements, the obligations of Mirant Power Purchase and Mirant s guarantee obligations terminate with respect to that agreement, and Pepco would be entitled to a claim in the Chapter 11 proceedings for any resulting damages. Pepco s damages claim would then be satisfied pursuant to the terms of the Plan. See *Chapter 11 Proceedings* above for further discussion of the treatment under the Plan of unresolved claims in the Chapter 11 proceedings.

If the proposed settlement between Mirant and Pepco described below in *Proposed Pepco Settlement* is approved and becomes effective, it will result in the dismissal of all pending litigation between Mirant and Pepco related to the APSA and the Back-to-Back Agreement. Under the settlement, the APSA will be assumed and performed by Mirant Power Purchase. The Back-to-Back Agreement will be rejected and terminated as of May 31, 2006, allowing Mirant to avoid the expected cost of the Back-to-Back Agreement through its stated expiration in 2021. Under certain conditions described below in *Proposed Pepco Settlement*, however, the settlement allows Mirant to assume and continue to perform, rather than reject, the Back-to-Back Agreement, thereby reducing the claim received by Pepco under the settlement and the amount that would have to be paid by Mirant to Pepco to satisfy that claim.

Potential Adjustment Related to Panda Power Purchase Agreement. At the time of the acquisition of the Mirant Mid-Atlantic assets from Pepco in December 2000, Mirant also entered into an agreement with Pepco that, as subsequently modified, provided that the price paid by Mirant for those assets would be adjusted if by April 8, 2005, a binding court order had been entered finding that the Back-to-Back Agreement violated the Panda PPA as a prohibited assignment, transfer or delegation of the Panda PPA or because it caused a prohibited delegation or transfer of rights, duties or obligations under the Panda

PPA that was not severable from the rest of the Back-to-Back Agreement. Panda initiated legal proceedings in 2000 asserting that the Back-to-Back Agreement violated provisions in the Panda PPA prohibiting Pepco from assigning the Panda PPA or delegating its duties under the Panda PPA to a third party without Panda s prior written consent. On June 10, 2003, the Maryland Court of Appeals, Maryland s highest court, ruled that the assignment of certain rights and delegation of certain duties by Pepco to Mirant under the Back-to-Back Agreement did violate the non-assignment provision of the Panda PPA and was unenforceable. The court, however, left open the issues whether the provisions found to violate the Panda PPA could be severed and the rest of the Back-to-Back Agreement enforced and whether Panda s refusal to consent to the assignment of the Panda PPA by Pepco to Mirant was unreasonable and violated the Panda PPA. Our view is that the June 10, 2003, decision by the Maryland Court of Appeals does not suffice to trigger a purchase price adjustment under the agreement between Mirant and Pepco. If that court order were found to have triggered the purchase price adjustment, the agreement between Mirant and Pepco provides that the amount of the adjustment would be negotiated in good faith by the parties or determined by binding arbitration so as to compensate Pepco for the termination of the benefit of the Back-to-Back Agreement while also holding Mirant economically indifferent from such court order.

If the proposed settlement between Mirant and Pepco described below in *Proposed Pepco Settlement* is approved and becomes effective, it would result in the termination of any potential adjustment to the price paid by Mirant for its December 2000 acquisition of the Pepco assets related to the Panda PPA with no amount being owed.

Pepco Avoidance Action. On July 13, 2005, Mirant and several of its subsidiaries filed a lawsuit against Pepco before the Bankruptcy Court asserting that Mirant did not receive fair value in return for the purchase price paid for the Pepco assets and that the acquisition occurred at a time when Mirant was either insolvent or was rendered insolvent as a result of the transaction. The suit seeks damages for fraudulent transfer under 11 U.S.C. §§ 544 and 550 and applicable state law and disallowance of claims filed by Pepco in the Chapter 11 proceedings. On November 3, 2005, the district court granted a motion filed by Pepco asking that the suit be heard by the district court rather than the Bankruptcy Court. If the proposed settlement between Mirant and Pepco described below in *Proposed Pepco Settlement* is approved and becomes effective, it would result in the release by Mirant and its subsidiaries of all claims asserted against Pepco in the suit filed July 13, 2005.

Proposed Pepco Settlement. On May 30, 2006, Mirant, Mirant Power Purchase, Old Mirant, various subsidiaries of Mirant, and a trust established pursuant to the Plan to which ownership of Old Mirant and Mirant Americas Energy Marketing was transferred (collectively the Mirant Settling Parties) entered into a Settlement Agreement and Release (the Settlement Agreement) with Pepco and various affiliates of Pepco (collectively the Pepco Settling Parties). Once it becomes effective, the Settlement Agreement will fully resolve the contract rejection motions that remain pending in the bankruptcy proceedings, as well as other matters currently disputed between Pepco and Mirant and its subsidiaries. The Pepco Settling Parties and the Mirant Settling Parties will release each other from all claims known as of May 30, 2006, including the fraudulent transfer claims brought by Old Mirant and several of its subsidiaries against Pepco in July 2005 that are described above in *Pepco Avoidance Action*. The Settlement Agreement will become effective once it has been approved by the Bankruptcy Court and that approval order has become a final order no longer subject to appeal. On August 9, 2006, the Bankruptcy Court entered an order approving the Settlement Agreement, but certain holders of unsecured claims against Old Mirant in the bankruptcy proceedings appealed that order. On December 26, 2006, the district court affirmed the bankruptcy court order approving the settlement, but the claims holders have appealed that ruling to the Fifth Circuit, and the approval order has not yet become a final order.

Under the Settlement Agreement, Mirant Power Purchase will perform any remaining obligations under the APSA, and Mirant will guaranty its performance. The Back-to-Back Agreement will be rejected and terminated effective as of May 31, 2006, unless Mirant exercises an option given to it under the

Settlement Agreement to have the Back-to-Back Agreement assumed under certain conditions. If the closing price of Mirant s stock is less than $16.00 on four business days in a 20 consecutive business day period prior to any distribution of shares to Pepco on its claim, then Mirant can elect to have the Back-to-Back Agreement assumed and assigned to Mirant Power Purchase rather than rejecting it, and the claim received by Pepco will be reduced as described below.

The Settlement Agreement grants Pepco a claim against Old Mirant in Old Mirant s bankruptcy proceedings that will result in Pepco receiving common stock of Mirant and cash having a value, after liquidation of the stock by Pepco, equal to $520 million, subject to certain adjustments. Upon the Settlement Agreement becoming effective, Mirant will distribute up to 18 million shares of Mirant common stock to Pepco to satisfy its claim and Pepco will liquidate those shares. The shares to be distributed to Pepco will be determined by Mirant after the Settlement Agreement becomes effective so as to produce upon liquidation total net proceeds as near to $520 million as possible, subject to the overall cap on the shares to be distributed of 18 million shares. If the net proceeds received by Pepco from the liquidation of the shares are less than $520 million, Mirant will pay Pepco cash equal to the difference. If Mirant exercises the option to have the Back-to-Back Agreement assumed, then the $520 million is reduced to $70 million, Mirant Power Purchase would continue to perform the Back-to-Back Agreement through its expiration in 2021, and Mirant would guarantee its performance. The Settlement Agreement allocates the $70 million to various claims asserted by Pepco that do not arise from the rejection of the Back-to-Back Agreement, including claims asserted under the Local Area Support Agreement between Pepco and Mirant Potomac River that are discussed in Pepco Assertion of Breach of Local Area Support Agreement in Note 23 to the consolidated financial statements.

While the appeal filed from the Bankruptcy Court s August 9, 2006, order approving the Settlement Agreement is pending, the parties will continue to perform their obligations under the Back-to-Back Agreement until the appeal is resolved and the approval order has become a final order. Unless the Back-to-Back Agreement is assumed, Pepco will refund to Mirant Power Purchase all payments received under the Back-to-Back Agreement for energy, capacity or other services delivered after May 31, 2006, through the date the Settlement Agreement becomes effective. The appeal of the approval order also resulted in Mirant paying Pepco $70 million. The $70 million will be repaid to Mirant when a final order is entered either affirming the approval order, which would cause the Settlement Agreement to become effective, or determining that the Settlement Agreement cannot be approved.

Upon the final distribution of the shares to Pepco, we expect to recognize a gain as a result of the rejection of the Back-to-Back Agreement. The amount of the gain will reflect the recorded price risk management liabilities for the Back-to-Back Agreement in the consolidated balance sheet at that date reduced by the amount of cash required to be paid by us in order for Pepco to receive the $520 million required under the Settlement Agreement. The closing price of our stock as of December 31, 2006, was $31.57 and the net proceeds at that price would have been sufficient to provide the $520 million to Pepco. As of December 31, 2006, the fair value of the Back-to-Back Agreement recorded in price risk management liabilities in our consolidated balance sheet totaled $425 million, of which $36 million is classified as current. Thus, the amount of the estimated contingent gain is approximately $445 million at December 31, 2006, including estimated refunds of $20 million for payments to Pepco under the Back-to-Back Agreement for periods since May 31, 2006. Until the final distribution of the shares to Pepco, the amount of the estimated gain is affected by changes in the fair value of the Back-to-Back Agreement, the number of common shares distributed to Pepco and the proceeds received by Pepco from its liquidation of the common shares.

Shareholder-Bondholder Litigation

Mirant Securities Consolidated Action. Twenty lawsuits filed in 2002 against Mirant and four of its officers have been consolidated into a single action, In re Mirant Corporation Securities Litigation, before

43

the United States District Court for the Northern District of Georgia. In their original complaints, the plaintiffs allege, among other things, that the defendants violated federal securities laws by making material misrepresentations and omissions to the investing public regarding Mirant s business operations and future prospects during the period from January 19, 2001, through May 6, 2002, due to potential liabilities arising out of its activities in California during 2000 and 2001. The plaintiffs seek unspecified damages, including compensatory damages, and the recovery of reasonable attorneys fees and costs.

In November 2002, the plaintiffs filed an amended complaint that added as defendants The Southern Company (Southern), the directors of Mirant immediately prior to its initial public offering of stock and various firms that were underwriters for the initial public offering by us. In addition to the claims set out in the original complaint, the amended complaint asserts claims under the Securities Act, alleging that the registration statement and prospectus for the initial public offering in 2000 of Mirant s old common stock terminated under the Plan misrepresented and omitted material facts. On July 14, 2003, the district court dismissed the claims asserted by the plaintiffs based on our California business activities but allowed the case to proceed on the plaintiffs other claims. On March 24, 2006, the plaintiffs filed a motion for reconsideration of that ruling, which motion remains pending. On December 11, 2003, the plaintiffs filed a proof of claim against Mirant in the Chapter 11 proceedings, but they subsequently withdrew their claim in October 2004. On August 29, 2005, the district court, at the request of the plaintiffs, dismissed Mirant as a defendant in this action.

A master separation agreement between Mirant and Southern entered into in conjunction with Mirant s spin-off from Southern in 2001 obligates Mirant to indemnify Southern for any losses arising out of any acts or omissions by Mirant and its subsidiaries in the conduct of the business of Mirant and its subsidiaries. Mirant has filed to reject the separation agreement in the Chapter 11 proceedings. Any damages determined to be owed to Southern arising from the rejection of the separation agreement will be addressed as a claim in the Chapter 11 proceedings under the terms of the Plan. The underwriting agreements between Mirant and the various firms added as defendants that were underwriters for the initial public offering by the Company in 2000 also provide for Mirant to indemnify such firms against any losses arising out of any acts or omissions by Mirant and its subsidiaries. The underwriters filed a claim against Mirant in the Chapter 11 proceedings that was subordinated to claims of Mirant s creditors and extinguished under the Plan.

U.S. Government Inquiries

Department of Justice Inquiries. In November 2002, we received a subpoena from the DOJ, acting through the United States Attorney s office for the Northern District of California, requesting information about our activities and those of our subsidiaries for the period since January 1, 1998.The subpoena requested information related to the California energy markets and other topics, including the reporting of inaccurate information to trade publications that publish natural gas or electricity spot price data. The subpoena was issued as part of a grand jury investigation. The DOJ s investigation is based upon the same circumstances that were the subject of an investigation by the CFTC that was settled in December 2004, as described in our Annual Report on Form 10-K for the year ended December 31, 2004, in *Legal Proceedings Other Governmental Proceedings CFTC Inquiry*. On June 19, 2006, two former employees pled guilty to charges of conspiracy to manipulate the price of natural gas in interstate commerce during the period from July 1, 2000, until November 1, 2000, while they were west region traders for Mirant Americas Energy Marketing. We are discussing the disposition of this matter with the DOJ. If we are unable to reach a consensual resolution with the DOJ, it is possible that the DOJ could seek indictments against one or more Mirant entities for alleged violations of the Commodity Exchange Act. A consensual resolution of this matter could involve a deferred prosecution agreement and payment of a fine or penalty. Our current assessment is that the amount of any such fine or penalty would not exceed amounts previously accrued.

Environmental Matters

EPA Information Request. In January 2001, the EPA issued a request for information to Mirant concerning the implications under the EPA s NSR regulations promulgated under the Clean Air Act of past repair and maintenance activities at the Potomac River plant in Virginia and the Chalk Point, Dickerson and Morgantown plants in Maryland. The requested information concerns the period of operations that predates our subsidiaries ownership and lease of those plants. Mirant 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 plants. If a violation is determined to have occurred at any of the plants, our subsidiary owning or leasing the plant 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 plants in Maryland will be installing a variety of emissions control equipment on those plants to comply with the Maryland Healthy Air Act, but that equipment will not include all of the emissions control equipment that could be required if a violation of the EPA s NSR regulations is determined to have occurred at one or more of those plants. If such a violation is determined to have occurred after our subsidiaries acquired or leased the plants or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, our subsidiary owning or leasing the plant 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 plant, 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 plants.

Mirant Potomac River Notice of Violation. On September 10, 2003, the Virginia DEQ issued an NOV to Mirant Potomac River alleging that it violated its Virginia Stationary Source Permit to Operate by emitting NOx in excess of the cap established by the permit for the 2003 summer ozone season. Mirant Potomac River responded to the NOV, asserting that the cap was unenforceable, noting that when the cap was made part of the permit it could comply through the purchase of emissions allowances and raising other equitable defenses. Virginia s civil enforcement statute provides for injunctive relief and penalties. On January 22, 2004, the EPA issued an NOV to Mirant Potomac River alleging the same violation of its Virginia Stationary Source Permit to Operate as set out in the NOV issued by the Virginia DEQ.

On September 27, 2004, Mirant Potomac River, Mirant Mid-Atlantic, the Virginia DEQ, the MDE, the DOJ and the EPA entered into, and filed for approval with the United States District Court for the Eastern District of Virginia, a proposed consent decree (the Original Consent Decree) that, if approved, would have resolved Mirant Potomac River s potential liability for matters addressed in the NOVs previously issued by the Virginia DEQ and the EPA. The Original Consent Decree would have required Mirant Potomac River and Mirant Mid-Atlantic to (1) install pollution control equipment at the Potomac River plant in Virginia and at the Morgantown plant in Maryland leased by Mirant Mid-Atlantic, (2) comply with declining system-wide ozone season NOx emissions caps from 2004 through 2010, (3) comply with system-wide annual NOx emissions caps starting in 2004, (4) meet seasonal system average emissions rate targets in 2008 and (5) pay civil penalties and perform supplemental environmental projects in and around the Potomac River plant expected to achieve additional environmental benefits. Except for the installation of the controls planned for the Potomac River units and the installation of selective catalytic reduction (SCR) or equivalent technology at Mirant Mid-Atlantic s Morgantown units 1 and 2 in 2007 and 2008, the Original Consent Decree would not have obligated our subsidiaries to install specifically designated technology, but rather to reduce emissions sufficiently to meet the various NOx caps. Moreover, as to the required installations of SCRs at Morgantown, Mirant Mid-Atlantic may choose not to install the technology by the applicable deadlines and leave the units off either permanently or until such time as the SCRs are installed. The Original Consent Decree was subject to the approval of the district court and the Bankruptcy Court. As described below, the Original Consent Decree was not approved and the parties have filed an amended proposed consent decree that supersedes the Original Consent Decree.

On July 22, 2005, the district court granted a motion filed by the City of Alexandria seeking to intervene in the district court action, although the district court imposed certain limitations on the City of Alexandria s participation in the proceedings. On September 23, 2005, the City of Alexandria filed a motion seeking authority to file an amended complaint in the action seeking injunctive relief and civil penalties under the Clean Air Act for alleged violations by Mirant Potomac River of its Virginia Stationary Source Permit to Operate and the State of Virginia s State Implementation Plan. Based upon a computer modeling described below in *Mirant Potomac River Downwash Study*, the City of Alexandria asserted that emissions from the Potomac River plant cause or contribute to exceedances of NAAQS for SO2, NO2 and particulate matter. The City of Alexandria also contended based on its modeling analysis that the plant s emissions of hydrogen chloride and hydrogen fluoride exceed Virginia state standards. Mirant Potomac River disputes the City of Alexandria s allegations that it has violated the Clean Air Act and Virginia law. On December 2, 2005, the district court denied the City of Alexandria s motion seeking to file an amended complaint.

In early May 2006, the parties to the Original Consent Decree and Mirant Chalk Point entered into and filed for approval with the United States District Court for the Eastern District of Virginia an amended consent decree (the Amended Consent Decree) that, if approved, will resolve Mirant Potomac River s potential liability for matters addressed in the NOVs previously issued by the Virginia DEQ and the EPA. The Amended Consent Decree includes the requirements that were to be imposed under the terms of the Original Consent Decree as described above. It also defines the rights and remedies of the parties in the event of a rejection in bankruptcy or other termination of any of the long-term leases under which Mirant Mid-Atlantic leases the coal units at the Dickerson and Morgantown plants. The Amended Consent Decree provides that if Mirant Mid-Atlantic rejects or otherwise loses one or more of its leasehold interests in the Morgantown and Dickerson plants and ceases to operate one or both of the plants, Mirant Mid-Atlantic, Mirant Chalk Point and/or Mirant Potomac will (i) provide the EPA, Virginia DEQ and the MDE with the written agreement of the new owner or operator of the affected plant or plants to be bound by the obligations of the Amended Consent Decree and (ii) where the affected plant is the Morgantown plant, offer to any and all prospective owners and/or operators of the Morgantown plant to pay for completion of engineering, construction and installation of the SCRs required by the Amended Consent Decree. If the new owner or operator of the affected plant or plants does not agree to be bound by the obligations of the Amended Consent Decree, it requires Mirant Mid-Atlantic, Mirant Chalk Point and/or Mirant Potomac to install an alternative suite of environmental controls at the plants they continue to own. The district court and the Bankruptcy Court must approve the Amended Consent Decree for it to become effective. The City of Alexandria and certain individuals and organizations have opposed entry of the Amended Consent Order. The Bankruptcy Court approved the Amended Consent Decree on June 1, 2006. The district court has not yet approved the Amended Consent Decree.

On April 26, 2006, Mirant Mid-Atlantic and the MDE entered into an agreement to allow Mirant Mid-Atlantic to implement the consent decree with respect to the Morgantown plant, if the consent decree receives the necessary approvals. Under the agreement, Mirant Mid-Atlantic agreed to certain ammonia and particulate matter emissions limits and to submit testing results to the MDE.

Mirant Potomac River Downwash Study. On September 23, 2004, the Virginia DEQ and Mirant Potomac River entered into an order by consent with respect to the Potomac River plant under which Mirant Potomac River agreed to perform a modeling analysis to assess the potential effect of downwash from the plant (1) on ambient concentrations of SO2, NO2, CO and PM10 for comparison to the applicable NAAQS and (2) on ambient concentrations of mercury for comparison to Virginia Standards of Performance for Toxic Pollutants. Downwash is the effect that occurs when aerodynamic turbulence induced by nearby structures causes emissions from an elevated source, such as a smokestack, to move rapidly toward the ground resulting in higher ground-level concentrations of emissions.

The computer modeling analysis predicted that emissions from the Potomac River plant have the potential to contribute to localized, modeled instances of exceedances of the NAAQS for SO2, NO2 and PM10 under certain conditions. Based on those results, the Virginia DEQ issued a directive to Mirant Potomac River on August 19, 2005, to undertake immediately such action as was necessary to ensure protection of human health and the environment and eliminate NAAQS violations. On August 24, 2005, power production at all five units of the Potomac River generating facility was temporarily halted in response to the directive from the Virginia DEQ. On August 25, 2005, the District of Columbia Public Service Commission filed an emergency petition and complaint with the FERC and the DOE to prevent the shutdown of the Potomac River facility. The matter remains pending before the FERC and the DOE. On December 20, 2005, due to a determination by the DOE that an emergency situation existed with respect to the reliability of the supply of electricity to central Washington, D.C., the DOE ordered Mirant Potomac River to generate electricity at the Potomac River generating facility, as requested by PJM, during any period in which one or both of the transmission lines serving the central Washington, D.C. area are out of service due to a planned or unplanned outage. In addition, the DOE ordered Mirant Potomac River, at all other times, for electric reliability purposes, to keep as many units in operation as possible and to reduce the start-up time of units not in operation without contributing to any NAAQS exceedances. The DOE required Mirant Potomac River to submit a plan, on or before December 30, 2005, that met these requirements. The order further provides that Mirant Potomac River and its customers should agree to mutually satisfactory terms for any costs incurred by it under this order or just and reasonable terms shall be established by a supplemental order. Certain parties filed for rehearing of the DOE order, and on February 17, 2006, the DOE issued an order granting rehearing solely for purposes of considering further the rehearing requests. Mirant Potomac River submitted an operating plan in accordance with the order. On January 4, 2006, the DOE issued an interim response to Mirant Potomac River s operating plan authorizing operation of the units of the Potomac River generating facility on a reduced basis, but making it possible to bring the entire plant into service within approximately 28 hours when necessary for reliability purposes. The DOE s order expires July 1, 2007, but Mirant Potomac River expects it will be able to continue to operate these units after that expiration.

In a letter received December 30, 2005, the EPA invited Mirant Potomac River and the Virginia DEQ to work with the EPA to ensure that Mirant Potomac River s operating plan submitted to the DOE adequately addressed NAAQS issues. The EPA also asserted in its letter that Mirant Potomac River did not immediately undertake action as directed by the Virginia DEQ s August 19, 2005, letter and failed to comply with the requirements of the Virginia State Implementation Plan established by that letter. Mirant Potomac River received a second letter from the EPA on December 30, 2005, requiring Mirant to provide certain requested information as part of an EPA investigation to determine the Clean Air Act compliance status of the Potomac River generating facility.

On June 1, 2006, Mirant Potomac River and the EPA executed an ACO by Consent to resolve the EPA s allegations that Mirant Potomac River violated the Clean Air Act by not immediately shutting down all units at the Potomac River facility upon receipt of the Virginia DEQ s August 19, 2005, letter and to assure an acceptable level of reliability to the District of Columbia. The ACO (i) specifies certain operating scenarios and SO2 emissions limits for the Potomac River facility, which scenarios and limits take into account whether one or both of the 230kV transmission lines serving Washington, D.C. are out of service; (ii) requires the operation of trona injection units to reduce SO2 emissions; and (iii) requires Mirant Potomac River to undertake a model evaluation study to predict ambient air quality impacts from the facility s operations. In accordance with the specified operating scenarios, the ACO permits the facility to operate using a daily predictive modeling protocol. This protocol allows Mirant Potomac River to schedule the facility s level of operations based on whether computer modeling predicts a NAAQS exceedance, based on weather and certain operating parameters. On June 2, 2006, the DOE issued a letter modifying its January 6, 2006, order to direct Mirant Potomac River to comply with the ACO in order to ensure adequate electric reliability to the District of Columbia. Mirant Potomac River is operating the Potomac River facility in accordance with the ACO and has been able to operate all five units of the facility most of the time under the ACO.

City of Alexandria Nuisance Suit. On October 7, 2005, the City of Alexandria filed a suit against Mirant Potomac River and Mirant Mid-Atlantic in the Circuit Court for the City of Alexandria. The suit asserted nuisance claims, alleging that the Potomac River plant s emissions of coal dust, flyash, NOx, SO2, particulate matter, hydrogen chloride, hydrogen fluoride, mercury and oil pose a health risk to the surrounding community and harm property owned by the City. The City sought injunctive relief, damages and attorneys fees. On February 17, 2006, the City amended its complaint to add additional allegations in support of its nuisance claims relating to noise and lighting, interruption of traffic flow by trains delivering coal to the Potomac River plant, particulate matter from the transport and storage of coal and flyash, and potential coal leachate into the soil and groundwater from the coal pile. On December 13, 2006, the City withdrew the suit.

Suit Regarding Chalk Point Emissions. By letter dated June 15, 2006, four environmental advocacy organizations Environmental Integrity Project, Chesapeake Climate Action Network, Patuxent Riverkeeper and Environment Maryland Research and Policy Center notified Mirant and Mirant Mid-Atlantic that they intended to file suit alleging that Mirant Chalk Point had violated the opacity limits set by the permits for Chalk Point unit 3 and unit 4 during thousands of six minute time intervals between January 2002 and March 2006. The letter indicated that the organizations intend to file suit to enjoin the violations alleged, to obtain civil penalties for past noncompliance to the extent that liability for these violations was not discharged by the bankruptcy of Mirant Chalk Point, and to recover attorneys fees. On August 3, 2006, Mirant, Mirant Mid-Atlantic, and Mirant Chalk Point filed a complaint in the Bankruptcy Court seeking an injunction barring the four organizations from filing suit as threatened in the June 15, 2006, notice on the grounds that the notice and any claim for civil penalties or other monetary relief for alleged violations occurring before January 3, 2006, violated the discharge of claims and causes of action granted Mirant Chalk Point under the Plan. On August 14, 2006, the Bankruptcy Court entered an order agreed to by the parties enjoining the four organizations from seeking monetary damages for any alleged violations occurring on or before January 3, 2006. As part of that order, the organizations agreed not to file a complaint initiating litigation concerning the alleged violations until August 30, 2006.

On August 29, 2006, MDE filed a complaint against Mirant Chalk Point in the Circuit Court for Prince George s County, Maryland, based upon the alleged violations of the opacity limits applicable to Chalk Point units 3 and 4 that were the focus of the June 15, 2006, notice letter from the environmental organizations and seeking civil penalties, injunctive relief and costs. Simultaneously with the filing of the complaint, Mirant Chalk Point and the MDE filed a proposed Consent Decree to resolve the issues raised by the Complaint. That Consent Decree was approved by the Maryland court on September 11, 2006. The Consent Decree subjects Chalk Point unit 3 to more stringent opacity and particulate standards and requires it when burning fuel oil to use fuel oil with a lower sulfur content than previously allowed under its permits. Mirant Chalk Point agreed in the Consent Decree to burn natural gas in Chalk Point units 3 and 4 for 95% of their heat input during certain months, subject to certain exceptions.

On August 30, 2006, the four environmental organizations filed suit in the United States District Court for the District of Maryland against Mirant, Mirant Mid-Atlantic, and Mirant Chalk Point asserting that emissions from Chalk Point units 3 and 4 had violated opacity limits set under the Clean Air Act and state law on numerous occasions since January 4, 2006. The plaintiffs sought an injunction prohibiting further violations by Chalk Point units 3 and 4 of the Clean Air Act, civil penalties of up to $32,500 for each violation of the Clean Air Act, additional civil penalties for mitigation projects, and attorneys fees. On September 22, 2006, the Mirant defendants filed a motion to dismiss, arguing that under the Clean Air

Act the MDE s prosecution of the same alleged violations in the Maryland state court proceeding and their resolution through the Consent Decree barred the plaintiffs suit. On January 3, 2007, the district court granted the motion and dismissed the complaint, and that order has become final.

Morgantown Particulate Emissions NOV. On March 3, 2006, Mirant Mid-Atlantic received a notice sent on behalf of the MDE alleging that violations of particulate matter emissions limits applicable to unit 1 at the Morgantown plant occurred on nineteen days in June and July 2005. The notice advises that the potential civil penalty is up to $25,000 per day for each day that unit 1 exceeded the applicable particulate matter limit. The letter further advises that the MDE has asked the Maryland Attorney General to file a civil suit under Maryland law based upon the alleged violations.

Morgantown SO2 Exceedances. Mirant Mid-Atlantic received an NOV dated March 8, 2006, asserting that on three days in June 2005 and January 2006, the Morgantown facility exceeded SO2 emissions limitations specified in its air permit. The NOV indicates that on two of those days the SO2 emissions limitation was exceeded by two different units of the Morgantown facility each day. The NOV did not seek a specific penalty amount but noted that the violations identified could subject Mirant Mid-Atlantic to a civil penalty of up to $25,000 per day.

Morgantown Emissions Observation NOV. On June 30, 2006, the MDE issued an NOV to Mirant Mid-Atlantic indicating that it had failed to comply with the air permit for the Morgantown facility by operating the combustion turbines at the facility for more than 168 hours without performing an EPA Reference Method 9 observation of stack emissions for an 18-minute period. The NOV did not seek a specific penalty amount but noted that the violation identified could subject Mirant Mid-Atlantic to a civil penalty of up to $25,000 per day.

Riverkeeper Suit Against Mirant Lovett. On March 11, 2005, Riverkeeper, Inc. filed suit against Mirant Lovett in the United States District Court for the Southern District of New York under the Clean Water Act. The suit alleges that Mirant Lovett failed to implement a marine life exclusion system at its Lovett generating plant and to perform monitoring for the exclusion of certain aquatic organisms from the plant s cooling water intake structures in violation of Mirant Lovett s water discharge permit issued by the State of New York. The plaintiff requests the court to enjoin Mirant Lovett from continuing to operate the Lovett generating plant in a manner that allegedly violates the Clean Water Act, to impose civil penalties of $32,500 per day of violation, and to award the plaintiff attorneys fees. On April 20, 2005, the district court approved a stipulation agreed to by the plaintiff and Mirant Lovett that stays the suit until 60 days after entry of an order by the Bankruptcy Court confirming a plan of reorganization for Mirant Lovett becomes final and non-appealable.

Mirant Canal NOV. On December 5, 2006, Mirant Canal received a notice of noncompliance from the Massachusetts DEP indicating that during August 2006, personnel from the Massachusetts DEP determined that the low NOx calibration gas cylinder for the continuous emission monitoring system (CEMS) for unit 1 of the Canal generating facility had an expiration date of December 23, 2005, which resulted in the CEMS being considered to be out-of-control after that date. The notice required Mirant Canal to review and update the facility CEMS operating and maintenance plan and CEMS quality control plan and to review and revise as necessary certain previously submitted reports. Further action may be taken by the Massachusetts DEP following its review of the information submitted by Mirant Canal in response to the notice.

City of Alexandria Zoning Action

On December 18, 2004, the City Council for the City of Alexandria, Virginia (the City Council) adopted certain zoning ordinance amendments recommended by the City Planning Commission that resulted in the zoning status of Mirant Potomac River s generating plant being changed from noncomplying use to nonconforming use subject to abatement. Under the nonconforming use status,

unless Mirant Potomac River applies for and is granted a special use permit for the plant during the seven-year abatement period, the operation of the plant must be terminated within a seven-year period, and no alterations that directly prolong the life of the plant will be permitted during the seven-year period. If Mirant Potomac River were to apply for and receive a special use permit for the plant, the City Council would likely impose various conditions and stipulations as to the permitted use of the plant and seek to limit the period for which it could continue to operate.

At its December 18, 2004, meeting, the City Council also approved revocation of two special use permits issued in 1989 (the 1989 SUPs), one applicable to the administrative office space at Mirant Potomac River s plant and the other for the plant s transportation management plan. Under the terms of the approved action, the revocation of the 1989 SUPs was to take effect 120 days after the City Council s action, provided, however, that if Mirant Potomac River within such 120-day period filed an application for the necessary special use permits to bring the plant into compliance with the zoning ordinance provisions then in effect, the effective date of the revocation of the 1989 SUPs would be stayed until final decision by the City Council on such application. The approved action further provides that if such special use permit application is approved by the City Council, revocation of the 1989 SUPs will be dismissed as moot, and if the City Council does not approve the application, the revocation of the 1989 SUPs will become effective and the plant will be considered a nonconforming use subject to abatement.

On January 18, 2005, Mirant Potomac River and Mirant Mid-Atlantic filed a complaint against the City of Alexandria and the City Council in the Circuit Court for the City of Alexandria. The complaint sought to overturn the actions taken by the City Council on December 18, 2004, changing the zoning status of Mirant Potomac River s generating plant and approving revocation of the 1989 SUPs, on the grounds that those actions violated federal, state and city laws. The complaint asserted, among other things, that the actions taken by the City Council constituted unlawful spot zoning, were arbitrary and capricious, constituted an unlawful attempt by the City Council to regulate emissions from the plant, and violated Mirant Potomac River s due process rights. Mirant Potomac River and Mirant Mid-Atlantic requested the court to enjoin the City of Alexandria and the City Council from taking any enforcement action against Mirant Potomac River or from requiring it to obtain a special use permit for the continued operation of its generating plant. On January 18, 2006, the court issued an oral ruling following a trial that the City of Alexandria acted unreasonably and arbitrarily in changing the zoning status of Mirant Potomac River s generating plant and in revoking the 1989 SUPs. On February 24, 2006, the court entered judgment in favor of Mirant Potomac River and Mirant Mid-Atlantic declaring the change in the zoning status of Mirant Potomac River s generating plant adopted December 18, 2004, to be invalid and vacating the City Council s revocation of the 1989 SUPs. The City of Alexandria filed a petition with the Virginia Supreme Court seeking to appeal this judgment, and on September 11, 2006, the Virginia Supreme Court agreed to hear the appeal.

New York Tax Proceedings

Mirant New York, Mirant Bowline, Mirant Lovett, and Hudson Valley Gas (collectively with Mirant New York, Mirant Bowline, and Mirant Lovett, the New York Companies) were the petitioners in various proceedings (Tax Certiorari Proceedings) initially brought in the New York state courts challenging the assessed values determined by local taxing authorities for the Bowline and Lovett generating facilities and a natural gas pipeline (the HVG Property) owned by Hudson Valley Gas. Mirant Bowline had challenged the assessed value of the Bowline generating facility and the resulting local tax assessments for tax years 1995 through 2006. Mirant Bowline succeeded to rights held by Orange & Rockland for the tax years prior to its acquisition of the Bowline Plant in 1999 under its agreement with Orange & Rockland for the purchase of that plant. Mirant Lovett had challenged the assessed value of the Lovett facility for each of the years 2000 through 2006. Hudson Valley Gas had challenged the assessed value of the HVG Property for each of the years 2004 through 2006.

As of December 31, 2006, Mirant Bowline and Mirant Lovett had not paid property taxes on the Bowline and Lovett generating facilities that fell due in the period from September 30, 2003, through September 30, 2006, in order to preserve their respective rights to offset the overpayments of taxes made in earlier years against the sums payable on account of current taxes. Hudson Valley Gas had not paid property taxes that fell due in the period from September 30, 2004, through September 30, 2006. The failure to pay these taxes when due potentially subjected Mirant Bowline, Mirant Lovett, and Hudson Valley Gas to additional penalties and interest.

On August 11, 2006, and August 28, 2006, the New York state court issued decisions addressing Mirant Bowline s challenges to the assessed values of the Bowline facility for the years 1995 to 2003 and Mirant Lovett s challenges to the assessed values of the Lovett facility for the years 2000 to 2003. Except for 1996, where it found that Mirant Bowline had failed to perfect its challenge to the assessed value of the Bowline facility, the New York state court concluded that the value of the Bowline facility and the Lovett facility in each year was substantially less than the assessed value set by the taxing authorities. Mirant Bowline and Mirant Lovett appealed the decisions of the New York state court, and the relevant taxing authorities cross-appealed.

On December 13, 2006, we and the New York Companies entered into a settlement agreement (the Settlement Agreement) with the Town of Haverstraw (Haverstraw), the Town of Stony Point (Stony Point), the Haverstraw-Stony Point Central School District (the School District), the County of Rockland (the County), the Village of Haverstraw (Haverstraw Village), and the Village of West Haverstraw (West Haverstraw Village and collectively with Haverstraw, Stony Point, the School District, the County, and Haverstraw Village, the Tax Jurisdictions). The Settlement Agreement was approved by the Bankruptcy Court on December 14, 2006, and resolved all pending disputes regarding real property taxes between the New York Companies and the Tax Jurisdictions. Under the agreement, the New York Companies accepted the determinations of assessed value for the Bowline Facility for 1995 through 2003 and the Lovett Facility for 2000 through 2003 made by the New York state court in its rulings in the Tax Certiorari Proceedings issued in August 2006. The New York Companies and the Tax Jurisdictions agreed to adopt the New York state court s assessed values for the Bowline Facility and the Lovett Facility for 2003 as the assessed values for each facility for 2004 through 2006. The parties agreed that the assessed values for the HVG Property for 2004 through 2006 should be the values determined previously by Haverstraw. The Tax Jurisdictions agreed to cancel penalties on the unpaid taxes owed by the New York Companies and to collect interest on those taxes at a rate of 8% per year for Mirant Bowline and Mirant Lovett and 12% per year for Hudson Valley Gas. Overall, the New York Companies under the settlement received total refunds of $163 million from the Tax Jurisdictions and paid unpaid taxes to the Tax Jurisdictions of $115 million, resulting in the New York Companies receiving a net cash payment in the amount of $48 million. The refunds and unpaid taxes were paid in early February 2007, and the New York Companies and the Tax Jurisdictions are in the process of dismissing all pending litigation related to the refunds and the unpaid taxes.

The $163 million of total refunds received by the New York Companies was recognized as a gain in the financial statements in the fourth quarter of 2006. In addition, the New York Companies had previously accrued a liability based upon the unpaid taxes as billed by the Tax Jurisdictions. Due to the reductions of the unpaid taxes that occurred pursuant to the terms of the Settlement Agreement, the New York Companies also recognized in the fourth quarter of 2006 a reduction of operating expenses of approximately $23 million related to 2006 and a gain of approximately $71 million related to prior periods.

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

None.

PART II

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

Common Stock

Pursuant to the Plan, all shares of old Mirant s common stock were cancelled on January 3, 2006, and 276,500,000 shares of New Mirant common stock were distributed to holders of unsecured claims and equity securities. In addition, we reserved 23,500,000 shares for unresolved claims, of which 21,113,104 have not yet been distributed as of December 31, 2006. New Mirant also issued two series of warrants, expiring January 3, 2011, that entitle their holders to initially purchase an aggregate of 52,941,177 shares of common stock. The Series A and Series B warrants entitle the holders to purchase an aggregate of 35,294,118 and 17,647,059 shares of common stock, respectively. The exercise price of the Series A and Series B warrants is $21.87 and $20.54 per share, respectively. On December 31, 2006, there were 35,205,678 Series A warrants and 17,635,897 Series B warrants yet to be exercised. New Mirant is authorized to issue 1,500,000,000 shares of common stock having a par value of $.01 per share and 100,000,000 shares of preferred stock having a par value of $.01 per share.

All of the New Mirant common stock was issued pursuant to the Plan in accordance with Section 1145 of the Bankruptcy Code, and we received no proceeds from such issuance. The issuance of New Mirant shares of 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 . The closing price of our stock on December 31, 2006, was $31.57. The following table sets forth the high and low sales prices for our common stock as reported by the NYSE for the periods indicated.

Price Range of Common Stock

Quarter	High	Low
First	$ 29.00	$ 23.93
Second	$ 26.86	$ 23.36
Third	$ 29.59	$ 26.02
Fourth	$ 32.61	$ 25.10

Holders

As of February 21, 2007, there were approximately 88,592 record holders of our common stock, par value $.01 per share.

Dividends

We will retain any future earnings to fund our operations and meet our cash and liquidity needs. 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.

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, 2006:

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, 2006 - Oct 31, 2006(1)	1.18	$ 27.11	1.18	$ 67.96
Nov 1, 2006 - Nov 30, 2006				$ 67.96
Dec 1, 2006 - Dec 31, 2006				$ 67.96
Total	1.18	$ 27.11	1.18	$ 67.96

(1) On September 28, 2006, we announced a share repurchase plan under which we can repurchase up to $100 million of common stock on the open market or in negotiated transactions. The plan expires in September 2007.

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, 2006:

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	4.4	$ 25.93	14.2
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	4.4	$ 25.93	14.2

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 of Reorganization.

Stock Performance Graph

The performance graph below compares the cumulative total stockholder return on Mirant s common stock with the Standard & Poor s Multi-Utility Index and the Standard & Poor s 500 Index since the re-issuance of our common stock in connection with our emergence from bankruptcy on January 3, 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 Mirant s 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.

Total Return to Shareholders
(Includes reinvestment of dividends)
Quarterly Return Percentage
Quarter Ending

Company / Index	3/31/2006	6/30/2006	9/30/2006	12/31/2006
Mirant Corporation	0.08 %	7.20 %	1.90 %	15.60 %
S&P 500 Index	0.51 %	(1.44)%	5.67 %	6.70 %
S&P 500 Multi-Utilities Index	(3.17)%	3.47 %	4.20 %	10.54 %
S&P 500 Independent Power Producers & Energy Traders	(1.92)%	19.28 %	7.07 %	(0.18)%

Indexed Returns
Quarter Ending

Company / Index	Base Period 1/11/2006	3/31/2006	6/30/2006	9/30/2006	12/31/2006
Mirant Corporation	$ 100	$ 100.08	$ 107.29	$ 109.33	$ 126.38
S&P 500 Index	100	100.51	99.06	104.68	111.69
S&P 500 Multi-Utilities Index	100	96.83	100.19	104.40	115.41
S&P 500 Independent Power Producers & Energy Traders	100	98.08	116.99	125.26	125.03

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 table presents our selected consolidated financial information, which is derived from our consolidated financial statements. Prior years have been revised to reflect the impact of our planned dispositions of the Philippine and Caribbean businesses and six U.S. natural gas-fired intermediate and peaking plants. See Note 3 to our consolidated financial statements for further discussion of our discontinued operations.

From July 14, 2003 (the Petition Date), through emergence, our consolidated financial statements were prepared in accordance with SOP 90-7. Our Statements of Operations Data for the years ended December 31, 2004 and 2003, do not include interest expense on debt that was subject to compromise subsequent to the Petition Date. Our Statements of Operations Data for the year ended December 31, 2005, reflects the effects of accounting for the Plan of Reorganization confirmed on December 9, 2005.

Our Statements of Operations Data for the years ended December 31, 2004, 2003 and 2002, include goodwill impairment losses of $582 million, $2.067 billion and $697 million, respectively.

Our Statement of Operations Data for the year ended December 31, 2006, reflects significant income tax benefits as discussed in Note 13 to our consolidated financial statements. Our Statement of Operations Data for the year ended December 31, 2002, includes the recognition of $949 million of provision for income taxes primarily related to valuation allowances for United States deferred tax assets.

	Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
	(in millions except per share data)				
Statements of Operations Data:					
Operating revenues	$ 3,103	$ 2,646	$ 3,248	$ 3,863	3,385
Income (loss) from continuing operations	1,773	(1,390)	1	(3,884)	(1,840)
Income (loss) from discontinued operations	91	99	(477)	78	(598)
Cumulative effect of changes in accounting principles		(16)		(29)	
Net Income (loss)	1,864	(1,307)	(476)	(3,835)	(2,438)
Basic EPS per common share from continuing operations	$ 6.22	N/A	N/A	N/A	N/A

The Consolidated Balance Sheet Data for years 2006, 2005, 2004 and 2003, segregates pre-petition liabilities subject to compromise from those liabilities that were not subject to compromise.

	Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Balance Sheet Data:					
Total assets	$ 11,536	$ 12,912	$ 11,424	$ 12,123	$ 19,423
Total long-term debt	3,275	2,582	38	288	7,408
Liabilities subject to compromise	18	18	9,164	9,036	
Company obligated mandatorily redeemable securities of a subsidiary holding solely parent company debentures					345
Stockholders equity (deficit)	$ 4,443	$ 3,856	$ (1,318)	$ (823)	$ 2,955

55

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, the Philippines and the Caribbean. Our continuing operations consist of power generation facilities located in the United States and our energy trading and marketing operations. Our continuing business consists of 10,650 MW located in markets that are characterized by low and declining reserve margins.

During the third quarter of 2006, we commenced separate auction processes to sell our Philippine and Caribbean businesses and certain of our U.S. natural gas-fired intermediate and peaking assets. On December 11, 2006, we entered into a definitive purchase and sale agreement with a consortium of The Tokyo Electric Power Company and Marubeni Corporation for the sale of our Philippine business for a purchase price of $3.424 billion, plus a working capital adjustment at the closing. After the payment of related debt, which is estimated to be $642 million at the closing, the net proceeds to Mirant are expected to be $3.121 billion after transaction costs. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions and the return to operation of both units at the Sual plant. Upon completion of the transaction, Mirant expects to record a pre-tax gain of approximately $2 billion.

In 2006, we have recognized a tax benefit in the amount of $721 million related to the pending sale of our Philippine business in 2007. This benefit has two components: a) $580 million recognized for continuing operations related to the release of the valuation allowance pertaining to deferred tax assets previously recorded including the estimated value of the NOLs that will be used to offset the anticipated 2007 taxable gain resulting from the sale; and b) $141 million recognized for our discontinued operations related to the value of the additional difference between the book basis and the tax basis in the shares of the entity being sold. Each year, our net U.S. Federal deferred tax assets have been reduced by a valuation allowance to reflect the amount that was estimated to be recoverable. It is our judgment based on available evidence that it is more-likely-than-not that deferred tax assets relating to this transaction will be recoverable in 2007. Management has considered all available positive and negative evidence affecting these specific deferred tax assets in making this decision and has determined that the valuation allowance related to such deferred tax assets should be released in 2006. In addition, based on the pending sale of the Philippine business, we no longer intend to distribute earnings in the form of a dividend prior to the completed sale. As a result, we have recognized an additional net tax benefit of $124 million in discontinued operations related to the reversal of previously accrued foreign withholding taxes.

On January 15, 2007, we entered into a definitive purchase and sale agreement with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively, LS Power), for the sale of six U.S. natural gas-fired plants for a purchase price of $1.407 billion, which includes estimated working capital and certain surplus generating equipment. After the payment of $83 million of related debt, the net proceeds are expected to be $1.307 billion after transaction costs. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions.

The auction and due diligence processes in respect of the sale of the Caribbean business are underway, and the sale of the Caribbean business is expected to close by mid-2007.

The primary factors affecting the earnings and cash flows of our continuing operations are the prices for power, emissions allowances, natural gas, oil and coal, which are largely driven by supply and demand. The increase in new generation capacity that followed the restructuring of the power markets in the late 1990s has created an oversupply situation in most markets which is expected to continue until 2008 to 2010. In certain markets in the United States, that excess has been absorbed or is close to being absorbed. Electricity demand has been growing and supply has not appreciably increased. Given the substantial time necessary to permit and construct new power plants, we think that the markets in the United States in which we operate need to begin the process now of adding generating capacity to meet growing demand. A number of key ISOs have implemented capacity markets as a way to encourage such construction of additional generation, but it is not clear whether the incentives offered will result in the construction of new generation.

Demand for power can also vary regionally and seasonally due to, among other things, weather and general economic conditions. Power supplies similarly vary by region and are affected significantly by available generating capacity, transmission capacity and federal and state regulation. We also are affected by the relationship between the prices for power and the prices for fuel, such as natural gas, coal and oil that affect our cost of generating electricity.

Hedging Activities. Prior to 2006, we hedged a substantial portion of our Mid-Atlantic baseload coal-fired generation and our New England intermediate oil-fired generation through OTC transactions. As a result, we achieved a significant increase in our realized gross margin for the year ended December 31, 2006, as compared to the same period in 2005 because our generation was hedged at higher gross margins for this period than for the same period in 2005. Our intermediate and peaking generation volumes generally were lower in the year ended December 31, 2006, than in 2005, due primarily to lower generation from our oil-fired units as a result of lower power prices combined with sharply higher oil prices in 2006.

In 2006 and thus far in 2007, our Mirant Mid-Atlantic subsidiary entered into financial swap transactions resulting in Mirant Mid-Atlantic being economically hedged for approximately 92%, 93%, 97% and 38% of its expected on-peak coal-fired baseload generation in 2007, 2008, 2009 and 2010, respectively. The financial swap transactions include new hedges in addition to the previously disclosed January 2006 hedges. These transactions are senior unsecured obligations of Mirant Mid-Atlantic and do not require the posting of cash collateral either for initial margin or for securing exposure due to changes in power prices. As of February 26, 2007, our total portfolio is economically hedged approximately 83%, 47%, 35% and 14% for 2007, 2008, 2009 and 2010, respectively. The corresponding fuel hedges are approximately 81%, 27%, 15% and 0% for 2007, 2008, 2009 and 2010 respectively.

New York Property Tax Settlement. On December 13, 2006, we entered into a settlement agreement with certain tax jurisdictions related to property tax assessments at the Bowline and Lovett generating facilities that resolves all pending disputes regarding refunds sought by us for property taxes paid for 1995 through 2003 and unpaid taxes assessed for 2003 through 2006. Under the settlement, we were awarded refunds totaling approximately $163 million for 1995 through 2003, against which were offset unpaid taxes of approximately $115 million for 2003 through 2006, resulting in a net cash payment in the amount of $48 million. The refunds were received and the unpaid taxes were paid in early February 2007. As a result of the refunds and the reduction in unpaid taxes under the settlement, we recognized a gain of approximately $244 million in the fourth quarter of 2006. Of the $244 million gain recognized, $163 million is included in reorganization items, net, and $94 million is a reduction in operations and maintenance expense in our consolidated statements of operations. These amounts are partially offset by $13 million in interest expense.

Capital Resources. Our business is subject to extensive environmental regulation by federal, state and local authorities. Our costs of complying with environmental laws, regulations and permits are substantial and difficult to estimate because we cannot always assess what regulations may be adopted or modified in the future or what costs might be associated with complying with the regulation. To comply with the requirements for SO2 and NOx emissions under the Maryland Healthy Air Act, we anticipate total capital expenditures of approximately $1.6 billion through 2009, including $80 million incurred through 2006. We expect that cash flows from operations will be sufficient to fund these capital expenditures.

A portion of our capital resources, in the form of cash and letters of credit, is needed to satisfy counterparty collateral requirements. These counterparty collateral requirements reflect our non-investment grade credit ratings, volatile energy prices, generally higher margin levels in the industry and other factors. Whenever feasible, we seek to structure transactions in a way that reduces our potential liquidity needs for collateral.

Our cash flows from financing activities reflect $1.261 billion of repurchases of common stock, third quarter debt issuances and repayments related to our discontinued operations, first quarter exit financing as part of our bankruptcy emergence and the first quarter payment of approximately $1.035 billion, of which $45 million relates to discontinued operations, of bankruptcy claims related to outstanding indebtedness.

Share repurchases. During the third quarter of 2006, we repurchased 43 million shares of Mirant common stock for an aggregate purchase price of approximately $1.23 billion. To pay for the shares tendered in the offer and related expenses, we utilized approximately $315 million of cash on hand at Mirant Corporation and approximately $915 million of distributions or repayments from our subsidiaries, including approximately $175 million and $740 million distributed or repaid from Mirant Americas Generation and Mirant Asia-Pacific Limited and its subsidiaries, respectively.

In August 2006, our Board of Directors authorized a $100 million share repurchase program. Accordingly, we intend, from time to time, until September 30, 2007, as business conditions warrant, to purchase shares of Mirant common stock on the open market or in negotiated transactions. We have repurchased 1.18 million shares for an aggregate purchase price of $32 million under this plan.

Use of Proceeds from Planned Dispositions. Upon completion of the business and asset sales, we plan to continue returning cash to our shareholders. The amount of cash returned will be based on preserving the credit profile of the continuing operations, retaining sufficient working capital to manage fluctuations in commodity prices and maintaining adequate liquidity for expected cash requirements including, among other things, capital expenditures. The sale of the Zeeland and Bosque plants is subject to the terms of the Mirant Americas Generation and Mirant North America indebtedness, including provisions with respect to the mandatory prepayment and/or reinvestment of the sale proceeds and the requirement to secure a credit rating affirmation.

Consolidated Financial Performance

We reported net income of $1.864 billion for the year ended December 31, 2006, and net losses of $1.307 billion and $476 million for the years ended December 31, 2005 and 2004, respectively. The change in net income is detailed as follows (dollars in millions):

	Years Ended December 31,					
	2006	2005	Increase/ (Decrease)	2005	2004	Increase/ (Decrease)
Gross margin	$ 1,947	$ 846	$ 1,101	$ 846	$ 1,089	$ (243)
Operating expenses:						
Operations and maintenance	609	698	(89)	698	718	(20)
Depreciation and amortization	137	135	2	135	137	(2)
Impairment losses	119	9	110	9	9	
Loss (gain) on sales of assets, net	(49)	17	(66)	17	49	(32)
Total operating expenses	816	859	(43)	859	913	(54)
Operating income (loss)	1,131	(13)	1,144	(13)	176	(189)
Total other expense (income), net	99	1,413	(1,314)	1,413	(50)	1,463
Income (loss) from continuing operations before reorganization items, net and income taxes	1,032	(1,426)	2,458	(1,426)	226	(1,652)
Reorganization items, net	(163)	(18)	(145)	(18)	227	(245)
Benefit for income taxes	(578)	(18)	(560)	(18)	(2)	(16)
Income (loss) from continuing operations	1,773	(1,390)	3,163	(1,390)	1	(1,391)
Income (loss) from discontinued operations	91	99	(8)	99	(477)	576
Cumulative effect of changes in accounting principles		(16)	16	(16)		(16)
Net income (loss)	$ 1,864	$ (1,307)	$ 3,171	$ (1,307)	$ (476)	$ (831)

Bankruptcy Considerations

While in bankruptcy, our financial results were volatile as asset impairments, asset dispositions, restructuring activities, contract terminations and rejections, and claims assessments significantly affected our consolidated financial results. As a result, our historical financial performance is not indicative of our financial performance post-bankruptcy.

At December 31, 2006 and 2005, amounts related to allowed claims, estimated unresolved claims and professional fees associated with the bankruptcy to be settled in cash were $28 million and $1.903 billion, respectively, and these amounts were recorded in claims payable and estimated claims accrual on the accompanying consolidated balance sheets. These amounts do not include unresolved claims that are expected to be settled in common stock or the stock portion of claims that are expected to be settled with cash and stock. During the year ended December 31, 2006, we paid approximately $1.849 billion in cash related to bankruptcy claims. Of this amount, $1.035 billion represents the principal amount of debt claims with $990 million reflected in cash flows from financing activities from continuing operations and $45 million reflected in cash flows from financing activities from discontinued operations. The remaining $814 million is reflected in cash flows from operating activities and represents other bankruptcy claims and related interest. As of December 31, 2006, approximately 21 million of the shares of Mirant common stock to be distributed under the Plan of Reorganization (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. However, up to 18 million of these reserved shares are proposed to be issued in settlement of the Pepco litigation. See Item 3. Legal Proceedings, Chapter 11 Proceedings.

Results of Operations

The following discussion of our performance is organized by reportable operating segment, which is consistent with the way we manage our business. Previously, we managed our business as three operating segments: United States, Philippines and Caribbean. In 2006, we commenced separate auction processes to dispose of our Caribbean and Philippine businesses and certain U.S. natural gas-fired assets. The planned sales have resulted in the reclassification of the revenues and expenses of these businesses and assets to discontinued operations and the reclassification of the related assets and liabilities to assets held for sale for all periods presented. In the fourth quarter of 2006, we re-evaluated the business segments of our continuing operations. As a result, we now have four operating segments: Mid-Atlantic, Northeast, California and Other Operations. For selected financial information about our business segments, see Note 20 to our consolidated financial statements contained elsewhere in this report.

In the tables below, the Mid-Atlantic region includes our Chalk Point, Morgantown, Dickerson and Potomac River facilities. The Northeast region includes our Bowline, Canal, Lovett, Kendall, Hillburn, Shoemaker, Martha s Vineyard, Swinging Bridge, Rio, Mongaup and Wyman facilities. The California region includes our Pittsburg, Contra Costa and Potrero facilities. Other Operations includes proprietary trading and fuel oil management activities and gains and losses related to the contractual arrangement with Pepco with respect to certain PPAs, including Pepco s long-term PPAs with Panda and Ohio Edison (the Back-to-Back Agreement) and TPAs with Pepco.

Operating Statistics

The following table summarizes capacity factor (average percentage of full capacity used over a year) by region for the years ended December 31, 2006, 2005 and 2004:

	Years Ended December 31,					
	2006	2005	(Decrease)	2005	2004	Increase/ (Decrease)
Mid-Atlantic	36 %	39 %	(3)%	39 %	40 %	(1)%
Northeast	17 %	34 %	(17)%	34 %	33 %	1 %
California	6 %	7 %	(1)%	7 %	17 %	(10)%
Total	24 %	31 %	(7)%	31 %	33 %	(2)%

The following table summarizes power generation volumes by region for the years ended December 31, 2006, 2005 and 2004 (in gigawatt hours):

	Years Ended December 31,					
	2006	2005	(Decrease)	2005	2004	Increase/ (Decrease)
Mid-Atlantic	16,607	18,200	(1,593)	18,200	18,712	(512)
Northeast	4,693	9,184	(4,491)	9,184	8,832	352
California	1,136	1,414	(278)	1,414	3,460	(2,046)
Total	22,436	28,798	(6,362)	28,798	31,004	(2,206)

2006 versus 2005

Gross Margin

The following table details gross margin by realized and unrealized margin for the year ended December 31, 2006 and 2005 (in millions):

	Years Ended December 31, 2006			2005		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Mid-Atlantic	$ 834	$ 484	$ 1,318	$ 552	$ (97)	$ 455
Northeast	297	61	358	216	(11)	205
California	112	3	115	113		113
Other Operations	11	107	118	(34)	92	58
Eliminations	38		38	15		15
Total	$ 1,292	$ 655	$ 1,947	$ 862	$ (16)	$ 846

Mid-Atlantic

Our Mid-Atlantic segment, which accounts for approximately half our generating capacity, includes four generation facilities with a total generation capacity of 5,256 MW. The following table summarizes the operations of our Mid-Atlantic segment for the years ended December 31, 2006 and 2005 (in millions):

	Years Ended December 31, 2006	2005	Increase/ (Decrease)
Realized Gross Margin	$ 834	$ 552	$ 282
Unrealized Gross Margin	484	(97)	581
Total Gross Margin	1,318	455	863
Operating expenses:			
Operations and maintenance	333	341	(8)
Depreciation and amortization	74	64	10
Gain on sales of assets, net	(7)		(7)
Total operating expenses	400	405	(5)
Operating income	918	50	868
Total other expense (income), net	(4)	18	(22)
Income from continuing operations before reorganization items and income taxes	$ 922	$ 32	$ 890

Gross Margin

Gross margin increased by $863 million for the year ended December 31, 2006, compared to the same period for 2005 and is detailed as follows (in millions):

	Years Ended December 31, 2006	2005	Increase/ (Decrease)
Energy	$ 558	$ 867	$ (309)
Contracted and capacity	39	64	(25)
Incremental realized value of hedges	237	(379)	616
Unrealized gains (losses)	484	(97)	581
Total	$ 1,318	$ 455	$ 863

61

Energy represents gross margin from the generation of electricity, emissions allowances sales and purchases, fuel sales, fuel purchases and handling, steam sales and our proprietary trading activities.

Contracted and capacity represents revenue received through RMR contracts and other installed capacity arrangements, revenues from ancillary services and revenue from the Back-to-Back Agreement.

Incremental realized value of hedges represents the actual margin upon the settlement of our power and fuel hedging contracts.

Unrealized gains/losses represent the unrealized portion of our derivative contracts.

The significant increase in the gross margin for our Mid-Atlantic operations is primarily due to the following:

- an increase of $581 million related to unrealized gains and losses on hedging activities. In 2006, unrealized gains of $484 million are primarily due to $312 million from increased value associated with forward power contracts for future periods as a result of decreases in forward power prices in 2006 and $172 million due to 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. In 2005, unrealized losses of $97 million were primarily due to increases in power prices as a result of increases in gas prices;

- an increase of $616 million in incremental realized value of hedges of our generation output. In 2006, the incremental realized value of our hedges contributed $237 million to our gross margin as our power contracts settled at prices higher than market prices for the year. In 2005, our opportunity cost of hedging was $379 million primarily due to the impact of rising energy prices in the latter part of 2005 that resulted in the settlement of power contracts at prices lower than market prices for that year; and

- a decrease of $309 million in energy primarily related to lower power prices and lower generation volume on our oil-fired units. Power prices were lower due to significantly lower gas prices in 2006 compared to 2005. Our baseload coal units generation decreased slightly and our 9% total decrease in generation volumes was driven by significantly lower volumes generated by our oil-fired units. A sharp decrease in power prices combined with average oil prices that were somewhat higher than in 2005 resulted in our oil-fired units not being able to dispatch economically for much of the year.

Northeast

Our Northeast segment is comprised of our assets located in New York and New England with a total generation capacity of 3,047 MW. The following table summarizes the operations of our Northeast segment for the years ended December 31, 2006 and 2005 (in millions):

	Years Ended December 31, 2006	2005	Increase/ (Decrease)
Realized Gross Margin	$ 297	$ 216	$ 81
Unrealized Gross Margin	61	(11)	72
Total Gross Margin	358	205	153
Operating expenses:			
Operations and maintenance	133	225	(92)
Depreciation and amortization	25	33	(8)
Impairment losses	118		118
Gain on sales of assets, net	(46)	(10)	(36)
Total operating expenses	230	248	(18)
Operating income (loss)	128	(43)	171
Total other expense, net	9	6	3
Income (loss) from continuing operations before reorganization items and income taxes	$ 119	$ (49)	$ 168

Gross Margin

Gross margin increased by $153 million for the year ended December 31, 2006, compared to the same period for 2005 and is detailed as follows (in millions):

	Years Ended December 31, 2006	2005	Increase/ (Decrease)
Energy	$ 125	$ 235	$ (110)
Contracted and capacity	47	36	11
Incremental realized value of hedges	125	(55)	180
Unrealized gains (losses)	61	(11)	72
Total	$ 358	$ 205	$ 153

The increase in gross margin is primarily due to the following:

- an increase of $72 million related to unrealized gains and losses on hedging activities. In 2006, unrealized gains of $61 million are primarily due to $50 million from increased value associated with forward power and fuel contracts for future periods mainly as a result of decreases in forward power prices in 2006 and $11 million due to 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. In 2005, unrealized losses of $11 million were primarily due to increases in power prices as a result of increased gas prices and the settlement of contracts during the year for which unrealized losses had been recorded in prior periods, partially offset by an increase in the value of fuel hedges due to higher fuel prices;

- an increase of $180 million in incremental realized value of hedges of our generation output. In 2006, the incremental realized value of our hedges contributed $125 million to our gross margin as our power contracts settled at prices higher than market prices for the year, partially offset by hedged fuel costs that were higher than the market. In 2005, our opportunity cost of hedging was $55 million primarily due to the impact of rising energy prices in the latter part of 2005 that resulted

in the settlement of power contracts at prices lower than market prices for that year, partially offset by the favorable impact of hedged fuel costs that were generally lower than the market as fuel prices increased in 2005; and

- a decrease of $110 million in energy primarily related to lower generation volumes. Our decrease in generation volumes was driven by significantly lower volumes generated by our oil-fired units. A decrease in power prices combined with average oil prices that were higher than in 2005 resulted in our oil-fired units not being able to dispatch economically for most of the period.

Operating Expenses

The decrease of $18 million in operating expenses is primarily due to a decrease of $92 million in operations and maintenance, of which $94 million relates to the New York property tax settlement. Of this amount, $71 million relates to periods prior to 2006. The remaining decrease in property tax expense represents the difference in the 2006 expense under the settlement compared to the 2005 expense that was accrued based on the property tax assessments. Gains on sales of assets increased $36 million due to an increase of $37 million in gains on sales of emissions allowances to affiliates that are eliminated in the consolidated statement of operations. Impairment losses in 2006 represent the impairment of the Bowline unit 3 suspended construction project.

California

Our California segment consists of the Pittsburg, Contra Costa and Potrero facilities with a total generation capacity of 2,347 MW. The following table summarizes the operations of our California segment for the years ended December 31, 2006 and 2005 (in millions):

	Years Ended December 31,		Increase/
	2006	2005	(Decrease)
Realized Gross Margin	$ 112	$ 113	$ (1)
Unrealized Gross Margin	3		3
Total Gross Margin	115	113	2
Operating expenses:			
Operations and maintenance	63	69	(6)
Depreciation and amortization	13	5	8
Total operating expenses	76	74	2
Operating income	39	39	
Total other expense (income), net	(34)	1	(35)
Income from continuing operations before reorganization items and income taxes	$ 73	$ 38	$ 35

Gross Margin

Gross margin increased by $2 million for the year ended December 31, 2006, compared to the same period for 2005 and is detailed as follows (in millions):

	Years Ended December 31,		Increase/
	2006	2005	(Decrease)
Energy	$ 14	$	$ 14
Contracted and capacity	101	114	(13)
Incremental realized value of hedges	(3)	(1)	(2)
Unrealized gains	3		3
Total	$ 115	$ 113	$ 2

The increase in our energy gross margin is primarily due to several days of extreme heat in July 2006, which allowed us to earn incremental gross margin on units that were under a tolling agreement for the same period in 2005. The expiration of this tolling agreement is the primary driver of the decrease in our contracted and capacity margin.

Other Expense, net

The decrease of $35 million in other expense, net is primarily due to a gain of $26 million in 2006 related to the transfer of Contra Costa unit 8 to PG&E and an increase of $6 million in interest income. See California Settlement in Note 23 to our consolidated financial statements for further discussion.

Other Operations

Other Operations includes proprietary trading, fuel oil management, and gains and losses related to our Back-to-Back Agreement and TPAs with Pepco. See Pepco Litigation in Note 23 to our consolidated financial statements for further discussion of the Back-to-Back Agreement. The following table summarizes the operations of our Other Operations segment for the years ended December 31, 2006 and 2005 (in millions):

	Years Ended December 31,		Increase/
	2006	2005	(Decrease)
Realized Gross Margin	$ 11	$ (34)	$ 45
Unrealized Gross Margin	107	92	15
Total Gross Margin	118	58	60
Operating expenses:			
Operations and maintenance	80	64	16
Depreciation and amortization	25	33	(8)
Impairment losses	1	9	(8)
Loss (gain) on sales of assets, net	(40)	19	(59)
Total operating expenses	66	125	(59)
Operating income (loss)	52	(67)	119
Total other expense, net	128	1,414	(1,286)
Loss from continuing operations before reorganization items and income taxes	$ (76)	$ (1,481)	$ 1,405

Gross Margin

Gross margin increased by $60 million for the year ended December 31, 2006, compared to the same period for 2005 and is detailed as follows (in millions):

	Years Ended December 31,		
	2006	2005	Increase
Energy	$ 71	$ 44	$ 27
Contracted and capacity	(60)	(78)	18
Unrealized gains	107	92	15
Total	$ 118	$ 58	$ 60

The increase in gross margin is primarily due to the following:

- an increase of $27 million in energy, primarily related to our proprietary trading and fuel oil management activities net of cost or market adjustments on our oil inventory during the third and fourth quarters of 2006;

- an increase of $18 million in contracted and capacity due to a decrease in realized losses on the Back-to-Back Agreement and the related hedges of this contract primarily due to the expiration of one of the PPAs under that agreement; and

- an increase of $15 million in unrealized gains and losses, which includes an increase of $73 million in unrealized gains on our proprietary trading and fuel oil management activities, partially offset by a decrease of $58 million in unrealized gains on the Back-to-Back Agreement and the related hedges.

Operating Expenses

The decrease of $59 million in operating expenses is primarily due to an increase in gain on sales of assets. In 2006, we recognized a $40 million gain from the sale of our remaining claims in the Enron bankruptcy. In 2005, we recognized a $19 million loss on sale of equipment from our Wyandotte suspended construction project.

Other Expense, net

Other expense, net in 2006 includes the interest expense on the debt of Mirant Americas Generation and Mirant North America. The decrease in other expense, net of $1.286 billion is primarily due to the following:

- in 2005, we recognized $1.2 billion of interest on liabilities subject to compromise for the period from the 2003 petition date through December 2005; and

- our gain on sales of investments increased $31 million. In 2006, we recognized a gain of $54 million related to sales of our investment in ICE and a gain of $19 million on the sale of our two New York Mercantile Exchange seats and shares. In 2005, we recognized a gain of $44 million related to the sale of a portion of our investment in ICE.

Other Significant Consolidated Statements of Operations Comparison

Reorganization Items, net

Reorganization items, net for the years ended December 31, 2006 and 2005, are comprised of the following (in millions):

	Years Ended December, 31,		
	2006	**2005**	**Increase/ (Decrease)**
Gain on the implementation of the Plan	$	$ (285)	$ 285
Gain on the New York property tax settlement	(163)		(163)
Estimated claims and losses on rejected and amended contracts	2	72	(70)
Professional fees and administrative expense		226	(226)
Interest income, net	(2)	(31)	29
Total	$ (163)	$ (18)	$ (145)

Reorganization items, net decreased by $145 million for the year ended December 31, 2006, compared to 2005, primarily related to the settlement of the New York State property tax disputes. Under the terms

66

of the settlement, in February 2007 we received refunds totaling approximately $163 million for 1995 through 2003 and paid unpaid taxes of approximately $115 million for 2003 through 2006. For the year ended December 31, 2005, reorganization items, net represent amounts that were recorded in the financial statements as a result of the bankruptcy proceedings.

Estimated claims and losses on rejected and amended contracts relate primarily to rejected energy contracts, such as tolling agreements, gas transportation contracts and electric transmission contracts.

Provision (Benefit) for Income Taxes

The $578 million net benefit for income taxes for the year ended December 31, 2006, is primarily due to the $580 million release of the valuation allowance pertaining to deferred tax assets previously recorded including the estimated value of the NOLs that will be used to offset the anticipated 2007 taxable gain resulting from the pending sale of the Philippine business in 2007. See Note 13 to the consolidated financial statements for further discussion.

Discontinued Operations

During the third quarter of 2006, we commenced separate auction processes to sell our Philippine and Caribbean businesses and six intermediate and peaking natural gas-fired plants in the United States. Accordingly, the results of operations related to the planned sales were reclassified to income (loss) from discontinued operations in our consolidated statements of operations for all periods presented.

For the year ended December 31, 2006, we reported net income from discontinued operations of $91 million, which includes the reclassification of the results of operations related to the planned dispositions and income related to the Wichita Falls facility. Included in income from discontinued operations are the following:

- an impairment loss of $375 million to write-down the U.S. natural gas-fired assets to estimated fair value;
- an income tax benefit of $141 million related to the disposition of the Philippine business; and
- a net tax benefit of $124 million related to the reversal of previously accrued foreign withholding taxes as a result of the decision, based on the pending sale of the Philippine business, to no longer distribute any accumulated earnings in the form of a dividend prior to the closing of the sale.

For the year ended December 31, 2005, we reported net income from discontinued operations of $99 million, which includes the reclassification of the results of operations related to the planned dispositions and income related to the Wichita Falls facility and the Wrightsville generating facility.

At December 31, 2005, we had deferred tax assets of $84 million related to the anticipated future tax benefits of unrealized foreign exchange losses arising from the U.S. dollar denominated borrowings of our Philippine entities. In the second quarter of 2006, final regulations governing the selection and use of a functional currency for Philippine tax reporting purposes became effective. We have determined that these regulations require us to maintain our local statutory filing in U.S. dollars converted to Philippine pesos for Philippine tax reporting purposes for all tax years ending after December 31, 2004. Accordingly, for 2006, we have recognized an additional income tax provision of $84 million. We also experienced an increase in the income tax provision of $23 million for the year ended December 31, 2006, related to the effects of the expiration of the Sual tax holiday in 2005, offset by the reversal of a $12 million tax contingency related to prior tax years.

See Note 3 to our consolidated financial statements for additional information related to planned dispositions and discontinued operations including updates on outages at our Sual generation facility and claims by NPC.

2005 versus 2004

The following table details gross margin by realized and unrealized margin for the year ended December 31, 2005 and 2004 (in millions):

	Years Ended December 31, 2005 Realized	Unrealized	Total	2004 Realized	Unrealized	Total
Mid-Atlantic	$ 552	$ (97)	$ 455	$ 576	$ (75)	$ 501
Northeast	216	(11)	205	197	31	228
California	113		113	143	3	146
Other Operations	(34)	92	58	1	209	210
Eliminations	15		15	4		4
Total	$ 862	$ (16)	$ 846	$ 921	$ 168	$ 1,089

Mid-Atlantic

The following table summarizes the operations of our Mid-Atlantic segment for the years ended December 31, 2005 and 2004 (in millions):

	Years Ended December 31, 2005	2004	Increase/ (Decrease)
Realized Gross Margin	$ 552	$ 576	$ (24)
Unrealized Gross Margin	(97)	(75)	(22)
Total Gross Margin	455	501	(46)
Operating expenses:			
Operations and maintenance	341	336	5
Depreciation and amortization	64	62	2
Total operating expenses	405	398	7
Operating income	50	103	(53)
Total other expense, net	18	3	15
Income from continuing operations before reorganization items and income taxes	$ 32	$ 100	$ (68)

Gross Margin

Gross margin decreased by $46 million for the year ended December 31, 2005, compared to the same period for 2004 and is detailed as follows (in millions):

	Years Ended December 31, 2005	2004	Increase/ (Decrease)
Energy	$ 867	$ 481	$ 386
Contracted and capacity	64	62	2
Incremental realized value of hedges	(379)	33	(412)
Unrealized losses	(97)	(75)	(22)
Total	$ 455	$ 501	$ (46)

The decrease in gross margin is primarily due to the following:

- a decrease of $412 million in incremental realized value of hedges primarily related to the impact of rising energy prices on the realized economic hedges of our generation output during the 2005 period;

• a decrease of $22 million related to unrealized gains and losses on hedging activities. In 2005, unrealized losses of $97 million included $207 million related to decreased value associated with forward power contracts for future periods resulting from increases in forward power prices late in the year, partly offset by $49 million related to increased value associated with forward fuel contracts for future periods resulting from increases in forward fuel prices late in the year. This was partially offset by unrealized gains of $61 million primarily due to the settlement of power contracts during the year for which unrealized losses had been recorded in prior periods; and

• an increase of $386 million in energy primarily related to higher market prices for power, partially offset by higher fuel costs during the year ended December 31, 2005, compared to the same period in 2004.

Northeast

The following table summarizes the operations of our Northeast segment for the years ended December 31, 2005 and 2004 (in millions):

	Years Ended December 31,		Increase/
	2005	2004	(Decrease)
Realized Gross Margin	$ 216	$ 197	$ 19
Unrealized Gross Margin	(11)	31	(42)
Total Gross Margin	205	228	(23)
Operating expenses:			
Operations and maintenance	225	200	25
Depreciation and amortization	33	31	2
Loss (gain) on sales of assets, net	(10)	43	(53)
Total operating expenses	248	274	(26)
Operating loss	(43)	(46)	3
Total other expense (income), net	6	(3)	9
Loss from continuing operations before reorganization items and income taxes	$ (49)	$ (43)	$ (6)

Gross Margin

Gross margin decreased by $23 million for the year ended December 31, 2005, compared to the same period for 2004 and is detailed as follows (in millions):

	Years Ended December 31,		Increase/
	2005	2004	(Decrease)
Energy	$ 235	$ 142	$ 93
Contracted and capacity	36	36	
Incremental realized value of hedges	(55)	19	(74)
Unrealized gains (losses)	(11)	31	(42)
Total	$ 205	$ 228	$ (23)

The decrease in gross margin is primarily due to the following:

• a decrease of $74 million in incremental realized value of hedges primarily related to the impact of rising energy prices on the realized economic hedges of our generation output during the 2005 period;

• a decrease of $42 million related to unrealized gains and losses on hedging activities. In 2005, unrealized losses of $11 million are primarily due to the settlement of power and fuel contracts during the year for which net unrealized gains had been recorded in prior periods. In 2004, the

settlement of hedges for which unrealized losses had been recognized in prior periods resulted in a gain of $17 million. In addition, the impact of rising fuel prices on forward fuel contracts, less the impact of rising power prices on forward power contracts, resulted in a gain of $14 million; and

- an increase of $93 million in energy primarily related to higher market prices for power, partially offset by higher fuel costs during the year ended 2005 compared to the same period in 2004.

Operating Expenses

The decrease of $26 million in operating expenses is primarily due to an increase of $53 million in gain on sales of assets. In 2004, we recognized a loss of $65 million on the sale of three natural gas combustion turbines partially offset by an increase of $25 million in operations and maintenance expense, which included increased maintenance costs of $8 million on the dam at Swinging Bridge and $5 million related to environmental remediation costs at the Lovett and Hillburn facilities.

California

The following table summarizes the operations of our California segment for the years ended December 31, 2005 and 2004 (in millions):

	Years Ended December 31,		Increase/
	2005	2004	(Decrease)
Realized Gross Margin	$ 113	$ 143	$ (30)
Unrealized Gross Margin		3	(3)
Total Gross Margin	113	146	(33)
Operating expenses:			
Operations and maintenance	69	80	(11)
Depreciation and amortization	5	4	1
Total operating expenses	74	84	(10)
Operating income	39	62	(23)
Total other expense, net	1	1	
Income from continuing operations before reorganization items and income taxes	$ 38	$ 61	$ (23)

Gross Margin

Gross margin decreased by $33 million for the year ended December 31, 2005, compared to the same period for 2004 and is detailed as follows (in millions):

	Years Ended December 31,		
	2005	2004	Decrease
Energy	$	$ 5	$ (5)
Contracted and capacity	114	127	(13)
Incremental realized value of hedges	(1)	11	(12)
Unrealized gains		3	(3)
Total	$ 113	$ 146	$ (33)

The decrease in gross margin is primarily due to the following:

- a decrease in contracted and capacity of $13 million related to the expiration of an RMR contract for one of our California generating facilities in 2004, partially offset by income from tolling agreements on those California assets not covered by RMR agreements; and

70

• a decrease of $12 million in the incremental realized value of hedges is due to favorable price spreads on both power and fuel contracts.

Other Operations

The following table summarizes the operations of our Other Operations segment for the years ended December 31, 2005 and 2004 (in millions):

	Years Ended December 31, 2005	2004	Increase/ (Decrease)
Realized Gross Margin	$ (34)	$ 1	(35)
Unrealized Gross Margin	92	209	(117)
Total Gross Margin	58	210	(152)
Operating expenses:			
Operations and maintenance	64	105	(41)
Depreciation and amortization	33	40	(7)
Impairment losses	9	9	
Loss (gain) on sales of assets, net	19	(12)	31
Total operating expenses	125	142	(17)
Operating income (loss)	(67)	68	(135)
Total other expense (income), net	1,414	(44)	1,458
Income (loss) from continuing operations before reorganization items and income taxes	$ (1,481)	$ 112	$ (1,593)

Gross Margin

Gross margin decreased by $152 million for the year ended December 31, 2005, compared to the same period for 2004 and is detailed as follows (in millions):

	Year Ended December 31, 2005	2004	Increase/ (Decrease)
Energy	$ 44	$ (13)	$ 57
Contracted and capacity	(78)	14	(92)
Unrealized gains	92	209	(117)
Total	$ 58	$ 210	$ (152)

The decrease in gross margin is primarily due to:

• a decrease of $92 million in contracted and capacity, which includes a decrease of $335 million in amortization on two TPAs into which we entered in connection with the acquisition of the Mid-Atlantic facilities from Pepco. Under the TPAs, we agreed to supply Pepco its full load requirement in the District of Columbia and in Maryland. The Maryland TPA expired in 2004 and the District of Columbia TPA expired in early 2005. The decrease related to the TPAs was partially offset by an increase of $243 million in realized losses on the Back-to-Back Agreement;

• an increase of $57 million in energy primarily related to an increase in realized gross margin from our proprietary trading and fuel oil management activities; and

• a decrease of $117 million related to unrealized gains and losses resulting from unrealized losses on derivative contracts for our proprietary trading and fuel oil management activities of $60 million and a decrease of $57 million in unrealized gains on the Back-to-Back Agreement and the related hedges of this contract.

Operating Expenses

The decrease of $17 million in operating expenses is primarily due to a decrease in operations and maintenance of $41 million, partially offset by an increase of $31 million in loss (gain) on sales of assets. The decrease in operations and maintenance is primarily due to a reduction in allocated corporate costs. In 2005, loss on sales of assets included $19 million related to the sale of equipment at our Wyandotte suspended construction project. In 2004, gain on sales of assets included $16 million related to the sale of our remaining Canadian natural gas transportation contracts and certain natural gas marketing contracts.

Other Expense, net

The increase in other expense (income), net of $1.458 billion is primarily due to the recognition in 2005 of $1.4 billion of interest on liabilities that were subject to compromise for the period from the Petition Date through December 31, 2005. In 2004, the Company recognized a gain of $37 million related to the extinguishment of $83 million of 2.5% convertible debentures due 2021 that were included in liabilities subject to compromise.

Other Significant Consolidated Statements of Operations Comparison

Reorganization Items, net

Reorganization items, net decreased by $245 million for the year ended December 31, 2005, compared to the same period in 2004. Reorganization items represent expense, income or gain and loss amounts that were recorded in the financial statements as a result of the bankruptcy proceedings. For the year ended December 31, 2005, this amount included:

	Years Ended December, 31, 2005	2004	Increase/ (Decrease)
Gain on the implementation of the Plan	$ (285)	$	$ (285)
Estimated claims and losses on rejected and amended contracts	72	132	(60)
Professional fees and administrative expense	226	109	117
Interest income, net	(31)	(14)	(17)
Total	$ (18)	$ 227	$ (245)

Estimated claims and losses on rejected and amended contracts relate primarily to rejected energy contracts, such as tolling agreements, gas transportation and electric transmission contracts and include a $32 million gain related to the California Settlement.

Provision (Benefit) for Income Taxes

The benefit for income taxes increased by $16 million for the year ended December 31, 2005, compared to 2004 primarily due to a favorable settlement of foreign taxes.

Discontinued Operations

For the year ended December 31, 2005, we reported income from discontinued operations of $99 million, which includes the reclassification of the results of operations related to the planned dispositions of the Philippine and Caribbean businesses and the six U.S. natural gas-fired plants and income related to the Wichita Falls facility.

For the year ended December 31, 2004, we reported a loss from discontinued operations of $477 million, which includes the reclassification of the results of operations related to the planned dispositions, income related to the Wichita Falls facility and the Wrightsville generating facility and an impairment charge of $48 million for the Coyote Springs 2 facility. Our loss from discontinued operations in 2004 included a $582 million impairment of the remaining goodwill related to our Philippine operations.

At December 31, 2005, we had deferred tax assets of $84 million related to the anticipated future tax benefits of unrealized foreign exchange losses arising from the U.S. dollar denominated borrowings of our Philippine entities. In the second quarter of 2006, final regulations governing the selection and use of a functional currency for Philippine tax reporting purposes became effective. We have determined that these regulations require us to maintain our local statutory filing in U.S. dollars converted to Philippine pesos for Philippine tax reporting purposes for all tax years ending after December 31, 2004. See Note 3 for additional information related to planned dispositions and discontinued operations including updates on outages at our Sual generation facility and claims by NPC.

Liquidity and Capital Resources

Overview

Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, capital expenditures, collateral requirements, fuel procurement and power sale contract obligations, legal settlements and working capital needs. Net cash flow provided by operating activities totaled $563 million, $33 million and $71 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Emergence from Bankruptcy

In connection with the consummation of the Plan on January 3, 2006, all shares of old Mirant s common stock were cancelled and 300 million new shares of common stock were issued, of which 276.5 million shares were distributed to holders of unsecured claims and equity securities, and 23.5 million shares were reserved for unresolved claims. We also issued two series of warrants, expiring January 3, 2011, that entitle the holders of these warrants to purchase an aggregate of approximately 53 million shares of common stock. In addition, approximately 19 million shares were reserved for issuance under the Omnibus Incentive Compensation Plan for employees and directors. Our authorized capital stock consists of 1.5 billion shares of common stock and 100 million shares of preferred stock. Further, the Plan eliminated approximately $5.9 billion of debt and approximately $2.6 billion of additional claims and disputes through the distribution or planned distribution of new common stock and $1.9 billion in cash among creditors. At December 31, 2006, approximately 21 million shares of common stock remain reserved for distribution in settlement of unresolved claims. However, up to 18 million of these reserved shares are proposed to be issued in settlement of the Pepco litigation. See Note 23 to our consolidated financial statements Chapter 11 Proceedings for further discussion of unresolved claims.

On December 23, 2005, in connection with our emergence from bankruptcy, our subsidiary Mirant North America issued $850 million of 7.375% senior unsecured notes due 2013 (the Old Notes). The Old Notes were issued in a private placement and were not registered with the SEC. The funds from this issuance initially were placed in escrow and were released from escrow on January 3, 2006. On August 4, 2006, Mirant North America completed an exchange offer for the Old Notes, whereby $849.965 million of senior notes registered under the Securities Act (the New Notes) were exchanged for an equal amount of the Old Notes. The terms of the New Notes are identical in all material respects to the Old Notes, except that the New Notes are registered under the Securities Act and generally are not subject to transfer restrictions or registration rights. On January 3, 2006, Mirant North America also entered into an $800 million senior secured revolving credit facility and a $700 million senior secured term loan. 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.

Sources of Funds and Capital Structure

The principal sources of liquidity for our future operations and capital expenditures are expected to be: (i) existing cash on hand and cash flows from the operations of our subsidiaries; (ii) borrowings under Mirant North America s $800 million six year senior secured revolving credit facility; (iii) $200 million of letters of credit capacity under Mirant North America s $700 million term loan; and (iv) proceeds from the sale of the Philippines, Caribbean and certain U.S. natural gas-fired plants. At December 31, 2006, we had approximately $1.027 billion of available cash and cash equivalents and $796 million available under our senior secured credit facilities.

Proceeds from the sales of the Zeeland and Bosque plants, expected to be approximately $500 million, will be reinvested in Mirant North America, a subsidiary of Mirant Americas Generation, and/or used to retire debt at Mirant North America. Several of the credit facilities and the capital markets debt of our Philippine and Caribbean subsidiaries contain change of control provisions. Such provisions provide creditors the right to require the borrowing entity to repay, in whole or in part, the amount owed by the borrower after the change in control occurs. Such change in control provisions would become effective upon the consummation of a transaction that triggers such provisions, such as a sale of our ownership interests in the respective subsidiary that is the obligor under such indebtedness. We expect that, in connection with all such sales, such indebtedness will be prepaid with the proceeds of long-term financing arranged by the purchasers or that the purchasers will obtain waivers of the change of control provisions from the existing lenders.

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

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 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 United States 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 us. Mirant Mid-Atlantic s ability to satisfy the criteria set by that covenant in the future could be impaired by factors which negatively affect the performance of its power generation facilities, including interruptions in operation or curtailment of operations to comply with environmental restrictions.

Uses of Funds

Our requirements for liquidity and capital resources, other than for the day-to-day operation of our generation facilities, are significantly influenced by three activities: (i) our asset management and proprietary trading activities; (ii) capital expenditures required to keep our power generation facilities in operation; and (iii) debt service.

Collateral Requirements. Our asset management and, to a lesser extent, proprietary trading activities represent a significant need for liquidity and capital resources. These liquidity requirements are primarily driven by margin and collateral posting requirements with counterparties and levels of inventory. As of December 31, 2006, we had approximately $227 million of posted cash collateral and $260 million of letters of credit outstanding primarily to support our asset management activities and debt service reserve requirements. Our liquidity requirements are highly dependent on the level of our hedging activity, forward prices for energy, emissions credits and fuel, commodity market volatility and credit terms with third parties.

Capital Expenditures. Capital expenditures for our continuing operations were $133 million, $101 million and $90 million for the years ended December 31, 2006, 2005 and 2004, respectively. Our capital expenditures for 2007 are expected to be approximately $826 million for our continuing business, with approximately $573 million of that amount for environmental capital expenditures needed to achieve compliance with the SO2 and NOx emissions requirements of 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, 2006, our continuing operations had approximately $3.3 billion of long-term debt with expected annual interest expense of approximately $256 million. 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 $7 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 by it of a net debt to EBITDA ratio of less than 2:1.

Mirant Mid-Atlantic Operating Leases

Mirant Mid-Atlantic leases the Morgantown and Dickerson baseload units and associated property through 2034 and 2029, respectively. Mirant Mid-Atlantic has an option to extend the leases. Any extensions of the respective leases would be limited to 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 rental expense for these leases on a straight-line basis in accordance with the applicable accounting literature. As of December 31, 2006, the total notional minimum lease payments for the remaining term of the leases aggregated approximately $2.2 billion and the aggregate termination value for the leases was approximately $1.4 billion and generally decreases over time. Rent expenses under the Mirant Mid-Atlantic leases were $96 million, $99 million and $103 million for the years ended December 31, 2006, 2005, and 2004, respectively. 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, fifty percent of the next twelve months rent or $75 million.

Use of Proceeds from Planned Dispositions

We plan to continue returning cash to our shareholders upon completion of the planned sales of our Philippine and Caribbean businesses and the six U.S. natural gas-fired plants. The amount of cash returned will be determined based on the outlook for the continuing business (1) to preserve the credit profile of the continuing business, (2) to maintain adequate liquidity for expected cash requirements including, among other things, capital expenditures for the continuing business and (3) to retain sufficient working capital to manage fluctuations in commodity prices. Proceeds from the sales of the Zeeland and Bosque plants, expected to be approximately $500 million, will be reinvested in Mirant North America, a subsidiary of Mirant Americas Generation, and/or used to retire debt at Mirant North America.

Cash Flows

2006 versus 2005

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. Cash provided by operating activities from continuing operations increased $504 million for the year ended December 31, 2006, compared to the same period in 2005, primarily due to the following:

- an increase in realized gross margin of $430 million for the year ended December 31, 2006, compared to the same period in 2005. See Results of Operations for additional discussion of our improved performance in 2006 compared to the same period in 2005;

- a decrease in energy trading collateral levels of $819 million in the year ended December 31, 2006, compared to the same period in 2005. The change in collateral requirements is due to the settlement of energy contracts combined with energy price declines in the year ended December 31, 2006, compared to the same period in 2005. For the year ended December 31, 2006, $592 million of cash collateral from brokers and counterparties has been returned to us. For the year ended December 31, 2005, additional net collateral used to support commercial operations was $227 million;

- an increase in bankruptcy related claims and expenses of $643 million. In 2006 we paid bankruptcy claims of $1.804 billion, of which $814 million is reflected in cash from operations. Our remaining claims payable and estimated claims accrual is $28 million at December 31, 2006. We paid $171 million in the year ended December 31, 2005 related to professional fees and other expenses associated with the bankruptcy proceedings; and

- a remittance of $70 million to Pepco in the third quarter of 2006. See Note 23 to our consolidated financial statements for further discussion of the settlement agreement with Pepco;

Investing Activities. Net cash provided by investing activities from continuing operations was $11 million for the year ended December 31, 2006, compared to $64 million for the same period in 2005. This difference was primarily due to the following:

- a decrease in proceeds from the sales of assets and investments of $22 million. In 2006, we received $143 million in proceeds from the sale of assets and investments, which included $45 million from the sale of bankruptcy claims against Enron and its subsidiaries, $12 million from the sale of the Mirant Service Center in Maryland and $58 million from sales of a portion of our investment in ICE. In 2005, proceeds from sales of assets and investments were $165 million and included $63 million in proceeds from the sale of Coyote Springs 2, $48 million from the sale of a portion of our investment in ICE, $4 million in additional proceeds from the 2004 sale of Bowline gas turbines and $44 million from the sale of Wyandotte s equipment and turbines; and

- an increase of $32 million in capital expenditures for 2006 as compared to 2005, primarily due to our environmental capital expenditures in 2006 in the Mid-Atlantic.

Financing Activities. Net cash used in financing activities from continuing operations was $758 million for the year ended December 31, 2006, compared to cash provided by financing activities of $97 million for the same period in 2005. This difference was primarily due to the following:

- the purchase of 43 million shares of our common stock for approximately $1.23 billion pursuant to our tender offer during the third quarter of 2006 and an additional 1.18 million shares for $32 million under a share repurchase plan in the fourth quarter of 2006;

• an increase in repayments of long-term debt comprised of the repayment of $465 million on the Mirant North America senior secured revolving credit facility and $990 million of principal payments for debt settled under the Plan; and

• an increase in proceeds from the issuance of long-term debt of approximately $2 billion. Proceeds from the issuance of long-term debt in 2006 included $850 million from the Mirant North America debt offering that was released from escrow on January 3, 2006, $700 million from the Mirant North America senior secured loan, and $465 million drawn on the Mirant North America senior secured revolving credit facility. In 2005, proceeds from the issuance of long-term debt represented pre-petition letters of credit being drawn upon by counterparties and banks.

Discontinued Operations

Operating Activities. Cash provided by operating activities from discontinued operations increased $26 million for the year ended December 31, 2006, compared to the same period in 2005, primarily due to the following:

• an increase of $62 million related to a decrease in restricted cash of our West Georgia subsidiary; and

• a decrease of $26 million due to an increase in payments for interest and taxes, primarily due to the expiration of the Sual tax holiday.

Investing Activities. Net cash used in investing activities from discontinued operations was $163 million for the year ended December 31, 2006, compared to cash provided by investing activities from discontinued operations of $15 million for the same period in 2005. This difference was primarily due to the following:

• the purchase in 2006 of the remaining 5.15% ownership in the Sual generating facility for $35 million and the purchase of the remaining 4.26% interest in Pagbilao facility for $40 million;

• a decrease of $82 million from the sale of assets and investments, primarily related to the sale of the Wrightsville assets in 2005; and

• *$30 million in funding by Mirant Trinidad Investments during 2006 for the construction and installation of new generating units at Point Lisas, Trinidad.*

Financing Activities. Net cash provided by financing activities from discontinued operations was $181 million for the year ended December 31, 2006, compared to cash used in financing activities of $142 million for the same period in 2005. This difference was primarily due to the following:

• an increase in proceeds from the issuance of $700 million of long-term debt related to the Philippines, $100 million by *Mirant Trinidad Investments*, $180 million by Mirant JPSCO Finance LTD and $9 million by Grand Bahama Power Company; partially offset by

• an increase of $678 million of repayments of long-term debt primarily due to the repayment in 2006 of $551 million of existing debt related to Pagbilao and Sual, $186 million by JPS, $73 million by Mirant Trinidad Investments and $56 million by West Georgia.

2005 versus 2004

Continuing Operations

Operating Activities. Cash used in operating activities from continuing operations increased $144 million for the year ended December 31, 2005, compared to the same period in 2004 primarily due to the following:

- a decrease in cash used due to a $277 million increase in gross margin, excluding unrealized gains and losses and TPA amortization. See Results of Operations for additional discussion;

- an increase in cash used of $231 million due to a $182 million increase in the collateral required to support commercial operations and $49 million of collateral posted related to the Mirant Mid-Atlantic leases;

- an increase in cash used of $117 million due to an increase in professional services and administrative expenses related to the bankruptcy proceedings; and

- an increase in cash used of $32 million for 2005 payments under the settlement agreement related to the Mirant Mid-Atlantic leases.

Investing Activities. Net cash provided by investing activities from continuing operations was $64 million for the year ended December 31, 2005, compared to cash used in investing activities from continuing operations of $56 million for the same period in 2004. The difference was primarily due to the following:

- in 2005, we had capital expenditures of $101 million compared to $90 million for the same period in 2004; and

- in 2005, proceeds from the sales of assets and investments was $165 million and included $63 million from the sale of Coyote Springs, $48 million from the sale of a portion of our investment in ICE, and $44 million from the sale of the Wyandotte and Mint Farm suspended construction projects. In 2004, proceeds from the sales of assets and investments was $45 million and included $42 million in proceeds from the disposal of three natural gas turbines related to suspended construction projects, partially offset by the payment of $12 million to exit our Canadian natural gas transportation agreements and certain natural gas contracts.

Financing Activities. Net cash provided by financing activities from continuing operations was $97 million for the year ended December 31, 2005, compared to cash provided by financing activities of $316 million for the same period in 2004. Proceeds from the issuance of debt, which represented pre-petition letters of credit being drawn upon by counterparties and banks, decreased by $218 million for the year ended December 31, 2005, compared to the same period in 2004.

Discontinued Operations

Operating Activities. Cash provided by operating activities from discontinued operations increased $106 million for the year ended December 31, 2005, compared to the same period in 2004 primarily due to the following;

- in 2004 our West Georgia and Shady Hills subsidiaries posted collateral of $24 million and $21 million, respectively. These amounts remain outstanding in 2005;

- an increase of $32 million primarily related to a decrease in prepaid transmission cost balances; and

- an increase of $28 million in the gross margin of our Caribbean operations.

Investing Activities. Net cash provided by investing activities from discontinued operations was $15 million for the year ended December 31, 2005, compared to cash used in investing activities from discontinued operations of $90 million for the same period in 2004. This difference was primarily due to the following:

- in 2005, we received $85 million from the sale of our Wrightsville generating facility; and

- in 2004, our Philippine business paid $21 million to acquire an additional interest in the Sual project after a minority shareholder exercised its put option.

Financing Activities. Net cash used in financing activities from discontinued operations was $142 million for the year ended December 31, 2005, compared to $343 million for the same period in 2004. This difference was primarily due to the following:

- in 2005, we had proceeds from the issuance of debt related to our Caribbean business of $25 million compared to proceeds from the issuance of debt related to our Caribbean business of $58 million in 2004. In addition, in 2005, our Caribbean operations received a net $19 million in proceeds from short-term debt. In 2004, our Jamaican operations repaid $14 million of short-term debt;

- in 2005, we repaid long-term debt of $159 million related to our Philippine operations and $37 million of debt related to our Caribbean operations. In 2004, we repaid long-term debt of $159 million related to our Philippine operations and $56 million related to our Caribbean operations; and

- in 2005, cash deposited in the debt service reserves related to our Philippine operations decreased by $25 million as compared to an increase in cash deposited in the debt service reserves related to our Philippine operations of $154 million in 2004. In 2005, we paid $16 million of dividends to minority interest holders as compared to $17 million in 2004.

Total Cash, Cash Equivalents and Credit Facility Availability

At December 31, 2006, we have total cash, cash equivalents, and credit facility availability of approximately $1.8 billion. The table below sets forth total cash, cash equivalents and availability of credit facilities of Mirant Corporation and its subsidiaries at December 31, 2006 and December 31, 2005 (in millions):

	At December 31, 2006	At December 31, 2005
Cash and Cash Equivalents:		
Mirant Corporation	$ 367	$ 354
Mirant Americas Generation		129
Mirant Mid-Atlantic	75	276
Mirant North America	678	19
Other	22	290
Total cash and cash equivalents	1,142	1,068
Less: Cash restricted due to bankruptcy of New York entities and reserved for working capital and other purposes	115	14
Total available cash and cash equivalents	1,027	1,054
Available under credit facilities	796	
Available under the DIP Facility		249
Total cash, cash equivalents and credit facilities availability	$ 1,823	$ 1,303
Cash and cash equivalents of discontinued operations	$ 243	$ 483

Mirant North America s ability to pay dividends is restricted under the terms of its debt agreements. At December 31, 2006, Mirant North America had distributed to its parent all available cash that was permitted to be distributed under the terms of its debt agreements. After taking into account the financial results of Mirant North America for the twelve months ended December 31, 2006, we expect Mirant North America will be able to distribute approximately $131 million in April 2007.

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 collateral posted in support of our business;
- effects of market price volatility on 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; and
- other unforeseen events.

Our capital expenditures for 2007 and 2008 are expected to be approximately $826 million and $802 million, respectively. This forecast does not assume any construction of new generating units in the United States during the forecast period. Instead, the current capital expenditure program, which is expected to be funded by operating cash flow, focuses on efficiency, safety, reliability, compliance with existing environmental laws and contract obligations. To comply with the requirements for SO2 and NOx emissions under the Maryland Healthy Air Act, we anticipate total capital expenditures of approximately $1.6 billion through 2009, including $80 million incurred through 2006.

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 are often required to provide trade credit support to our counterparties or make deposits with brokers. In addition, we are often required to provide cash collateral or letters of credit for access to the transmission grid, to participate in power pools, to fund debt service 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. At December 31, 2006, our outstanding issued letters of credit totaled $260 million.

The following table summarizes cash collateral posted with counterparties and brokers and letters of credit issued as of December 31, 2006 and 2005 (in millions):

	At December 31, 2006	At December 31, 2005
Continuing operations:		
Cash collateral posted energy trading and marketing	$ 27	$ 619
Cash collateral posted debt service and rent reserves		56
Cash collateral posted other operating activities	13	11
Letters of credit energy trading and marketing	100	51
Letters of credit debt service and rent reserves	84	
Letters of credit other operating activities	15	2
	239	739
Discontinued operations:		
Assets held for sale cash collateral posted	187	301
Assets held for sale letters of credit	61	56
Total	$ 487	$ 1,096

On July 13, 2006, Moody s Investors Service reduced our corporate credit rating to B2 and the debt ratings of our subsidiaries were also lowered. Standard and Poor s also announced that they had placed our corporate credit rating and the debt ratings of our subsidiaries on credit watch.

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

Our debt obligations, off-balance sheet arrangements and contractual obligations as of December 31, 2006, are as follows (in millions):

	Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations by Year						
	Total	**2007**	**2008**	**2009**	**2010**	**2011**	**>5 years**
Mirant Mid-Atlantic operating leases	$ 2,246	$ 112	$ 121	$ 142	$ 140	$ 134	$ 1,597
Other operating leases	72	9	9	9	9	8	28
Long-term debt	5,728	397	261	260	260	1,063	3,487
Claims payable and estimated claims accrual	28	28					
Purchase commitments:							
Long-term service agreements	33	3	1	2	2	2	23
Fuel and transportation commitments	418	263	89	66			
PPAs	779	53	52	52	54	58	510
Other purchase commitments	223	223					
Total excluding liabilities subject to compromise	9,527	1,088	533	531	465	1,265	5,645
Liabilities subject to compromise	18						
Discontinued operations	1,895						
Total debt obligations, off-balance sheet arrangements and contractual obligations	$ 11,440						

Operating leases are off-balance sheet arrangements and are discussed in Note 16 to our consolidated financial statements contained elsewhere in this report. These amounts primarily relate to our minimum lease payments associated with our lease of the Morgantown and Dickerson baseload units.

Long-term debt includes the current portion of long-term debt and long-term debt on the consolidated balance sheets which are discussed in Note 10 to our consolidated financial statements contained elsewhere in this report. Long-term debt also includes estimated interest on debt based on a U.S. Dollar LIBOR curve as of January 2, 2007.

Claims payable and estimated claims accrual primarily consists of allowed bankruptcy claims, estimated unresolved bankruptcy claims that are to be settled in cash and professional fees associated with the bankruptcy proceedings.

Long-term service agreements represent our total estimated commitments under our long-term service agreements associated with turbines installed or in storage and are discussed in Note 16 to our consolidated financial statements contained elsewhere in this report.

Fuel and transportation commitments primarily relate to long-term coal agreements and other fuel purchase and transportation agreements and are discussed in Note 16 to our consolidated financial statements contained elsewhere in this report. The fair value of certain contracts is included in price risk management assets or price risk management liabilities on our consolidated balance sheets.

PPAs are discussed in Note 17 to our consolidated financial statements contained elsewhere in this report. These amounts represent the estimated commitments under the PPAs that Mirant assumed in the asset purchase and sale agreement for the Pepco generating assets. The estimated commitment is based on the contractual dependable capacity rate at contractual prices. These contracts are accounted for as derivatives. The fair value of certain agreements at December 31, 2006, is included in price risk management liabilities on our consolidated balance sheets.

Other purchase commitments represent the 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 generation facilities.

Liabilities subject to compromise on the consolidated balance sheets at December 31, 2006, relate only to our New York subsidiaries that remain in bankruptcy and are discussed in Note 12 to our consolidated financial statements contained elsewhere in this report.

Discontinued operations include the debt and obligations related to our planned dispositions of our Philippine and Caribbean businesses and certain U.S. natural gas-fired assets.

Critical Accounting Policies and 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 impact 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 in reporting our consolidated financial position and results of operations as required by GAAP an accrual model and a fair value model. We determine the appropriate model for our operations based on applicable accounting standards.

The accrual model has historically been used to account for our generation revenue from the sale of energy, capacity and ancillary services and to account for distribution revenue from the sale and distribution of energy. We recognize revenue when earned and collection is probable as a result of electric power 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, based on member participation agreements, but without an underlying contractual commitment. ISO 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. Our distribution revenue is reflected in income (loss) from discontinued operations in the consolidated statements of operations.

The fair value model has historically been used for derivative energy contracts that economically hedge our electricity generation assets or that are used in our proprietary trading activities. We use a variety of derivative contracts, such as futures, swaps and option contracts, in the management of our business. Such derivative contracts 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 No. 133, derivative contracts 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. We currently defer inception gains and losses in accordance with EITF 02-3. Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of completing forecasted transactions 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 contracts is included in price risk management assets and liabilities in our consolidated balance sheets. Transactions that do not qualify for accounting under SFAS No. 133, either because they are not derivatives or because they qualify for a scope exception, are accounted for under accrual accounting as described above.

Key Assumptions and Approach Used. Determining the fair value of derivatives involves significant estimates based largely on the mid-point of quoted prices in active markets. The mid-point may vary significantly from the bid or ask price for some delivery points. If no active market exists, we estimate the fair value of certain derivative contracts using quantitative pricing models. Fair value estimates involve uncertainties and matters of significant judgment. Our modeling techniques for fair value estimation include assumptions for market prices, supply and demand market data, correlation and volatility. The degree of complexity of our pricing models increases for longer duration contracts, contracts with multiple pricing features, option contracts and off-hub delivery points.

The fair value of price risk management assets and liabilities in our consolidated balance sheets is also affected by our assumptions as to interest rate, counterparty credit risk and liquidity 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 contracts is reduced to reflect the estimated risk of default of counterparties on their contractual obligations to us.

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 No. 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 due to changes in energy and fuel prices. Due to the complexity of the models used to value some of the derivative instruments each period, a significant change in estimate could have a material impact on our results of operations and cash flows at the time contracts are ultimately settled. See Note 7 to our consolidated financial statements for further information on financial instruments related to energy trading and marketing activities.

For additional information regarding accounting for derivative instruments, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

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 composite depreciation for groups of similar assets and establish an average useful life for each group of related assets. In accordance with SFAS No. 144, we cease depreciation on long-lived assets classified as available for sale. See Note 8 to our consolidated financial statements 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. 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 No. 143 and under FIN 47. SFAS No. 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 No. 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 retirement obligations within our power generation operations in the United States and have a noncurrent liability of $41 million recorded as of December 31, 2006. 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.

Key Assumptions and Approach Used. The fair value of liabilities associated with 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. However,

due to changes in inflation assumptions, interest rates and asset useful lives, actual future cash flows required to satisfy asset retirement obligations could differ materially from the current recorded liabilities.

Asset Impairments

Nature of Estimates Required. We evaluate our long-lived assets, including goodwill and indefinite-lived 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.

Property, Plant and Equipment and Definite-Lived Intangibles

SFAS No. 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 is less than the carrying value of that asset. We evaluate our long-lived assets (property, plant and equipment) and definite-lived intangibles for impairment whenever indicators of impairment exist or when we commit to sell the asset. These evaluations of long-lived assets and definite-lived intangibles 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 operations analyses. If the carrying amount is not recoverable, an impairment charge is recorded.

Key Assumptions and Approach Used. The fair value of an asset is the amount at which the asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. 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. 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 selecting a discount rate that reflects the risk inherent in future cash flows.

On July 11, 2006, we announced the commencement of separate auction processes to dispose of our Caribbean and Philippine businesses. The planned sales resulted in the reclassification of the long-lived assets related to these businesses as held for sale at December 31, 2006. On December 11, 2006, we entered into a purchase and sale agreement with a consortium of The Tokyo Electric Power Company and Marubeni Corporation for the sale of our Philippine business for a purchase price of $3.424 billion subject to a working capital adjustment at the closing. As such, we did not record an impairment during the period, as the fair value less cost to sell for the Philippines exceeded the book carrying value. We received non-binding indicative bids for the Caribbean assets in November. Based on a review of the bids, it remains more-likely-than-not that the Caribbean business will be sold in a single transaction. We determined that no impairment was necessary in the fourth quarter as bids from potential buyers exceeded the carrying value of the assets.

On August 9, 2006, we announced the planned sale of 3,619 MW of the following intermediate and peaking natural gas-fired plants: Zeeland, West Georgia, Shady Hills, Sugar Creek, Bosque and Apex. The planned sales resulted in the reclassification of the long-lived assets related to these plants as held for sale at December 31, 2006. During the third quarter of 2006, the Company reviewed each asset independently for impairment through the allocation of the fair value of the portfolio. As a result of this review, the Company recorded a loss of $396 million to write down the assets to their estimated fair value.

On January 15, 2007, we entered into a definitive purchase and sale agreement with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively, LS Power), for the sale of the six natural gas-fired plants discussed above for a purchase price of $1.407 billion, which includes estimated working capital at the closing. The purchase and sale agreement assigned a value to the Mirant North America plants as a whole, as well as the Mirant Americas plants as a whole. The updated fair values along with changes to the working capital calculation in the draft purchase and sale agreement provided to the bidders, resulted in a reduction to the impairment loss of $21 million, which was recorded in the fourth quarter of 2006. The net 2006 impairment loss of $375 million was recorded in discontinued operations in our consolidated financial statements of operations during the year to decrease the carrying value of the assets to their fair value less costs to sell.

During the third quarter of 2006, our estimates of cash flows related to our impairment analysis of our Lovett and Bowline generation facilities required significant judgment related to the outcome of property tax disputes and future tax assessments for Lovett and Bowline. Our estimates also required prediction of the likelihood of various outcomes of unresolved matters related to environmental controls and a reasonable economic return for our Lovett generation facility. See Note 4 to our consolidated financial statements where further discussed.

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. Due to the nature of the auction process for the assets held for sale, the ultimate sales price at the end of the auction could differ from our current estimates of fair value determined through discounted cash flows or non-binding indicative bids for those assets. 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 Notes 3 and 4 to our consolidated financial statements for additional information on impairments.

Goodwill and Indefinite-Lived Intangible Assets

The evaluations of goodwill and indefinite-lived intangibles are conducted at least annually and periodically if indicators of impairment are present in accordance with SFAS No. 142. The results of our impairment testing may be affected by a significant adverse change in the extent or manner in which a reporting unit s assets are being used, a significant adverse change in legal factors or in the business climate that could affect the value of a reporting unit, as well as other economic or operational analyses. If the carrying amount of the reporting unit is not recoverable, an impairment charge is recorded. The amount of the impairment charge, if an impairment exists, is calculated as the difference between the fair value of the goodwill and its carrying value. We perform our annual assessment of goodwill at October 31 and whenever contrary evidence exists as to the recoverability of goodwill. We impaired our remaining goodwill of $582 million in 2004. At December 31, 2006, our entire goodwill balance of $6 million is included in assets held for sale.

Equity Method Investments

Investments accounted for by the equity method are reviewed for impairment in accordance with APB 18, which requires that a loss in value of an investment that is other than a temporary decline should be recognized. We identify and measure other than temporary losses in the value of equity investments based upon a comparison of fair value to carrying value. At December 31, 2006, our entire equity-method investments balance of $224 million is included in assets held for sale.

Stock-Based Compensation

Nature of Estimates Required. We account for stock-based compensation under SFAS No. 123R. SFAS No. 123R requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. We consider the assumptions inherent in our valuation and calculation of compensation expense critical to the financial statements because the underlying assumptions are subject to significant judgment and the resulting compensation expense is a new expense item in 2006 and may be material to our results of operations.

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 impact on the option s fair value. The expected term and expected volatility often have the most impact on the fair value of the option. The inputs to the Black-Scholes model that we used for the year ended December 31, 2006, are detailed below:

	Range		Weighted Average	
Expected volatility	21 - 37	%	31.64	%
Expected dividends	0	%	0	%
Expected term:				
Service condition awards	5.2 - 6 years		5.9 years	
Performance condition awards	3 years		3 years	
Risk-free rate	4.3 - 5.1	%	4.5	%

Pursuant to the Plan, all shares of Mirant s old common stock were cancelled, and shares of Mirant s new common stock were issued. Due to Mirant s bankruptcy and other factors, historical information concerning the stock price volatility for purposes of valuing stock option grants was not sufficient indication of expected stock price volatility for options granted in the months immediately following Mirant s emergence from bankruptcy. 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 2006, we 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 No. 107. Additionally, we assumed there would be no dividends paid over the five-to-six year expected term of the awards. Due to the lack of exercise history for the Company, the simplified method for estimating expected term has been used in accordance with SAB No. 107, to the extent applicable. For performance condition awards, we utilized the contractual term as the expected term. The grant price used in the Black-Scholes option pricing model is the New York Stock Exchange 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 2006 qualify for equity accounting treatment under SFAS No. 123R. 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. Compensation cost has been adjusted for an estimated forfeiture rate of 3%. As we accumulate participant history, the forfeiture rate will be adjusted for actual forfeitures. During the year ended December 31, 2006, we recognized approximately $16 million of compensation expense related to service condition awards and $1 million related to performance condition awards.

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 share-based payment accounting could result in material changes to our financial statements if different assumptions are used.

Compensation expense recognized for stock options would differ to the extent other assumptions were used in the valuation of options. Generally, as the expected term, expected volatility and risk-free rate increase, the option s fair value increases due to 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 14 to our consolidated financial statements for further information on stock-based compensation.

Income Taxes

Nature of Estimates Required. We currently record a tax provision for foreign, state and federal income taxes including any alternative minimum tax as appropriate. We also recognize deferred tax assets and liabilities based on the difference between the financial statement carrying amounts and the tax basis of the assets and liabilities. When necessary, deferred tax assets are reduced by a valuation allowance to reflect the amount that is estimated to be recoverable. In assessing the recoverability of our deferred tax assets, we consider whether it is likely that some portion or all of the deferred tax assets will be realized. See Note 13 to our consolidated financial statements for additional information regarding our deferred tax assets and the application of our NOLs.

Key Assumptions and Approach Used. The determination of a valuation allowance requires significant judgment as to the generation of taxable income during future periods for which temporary differences are expected to be deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including our past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

Additionally, we have contingent liabilities related to tax uncertainties arising in the ordinary course of business. We periodically assess our contingent liabilities in connection with these uncertainties based on the latest information available. For those uncertainties where it is probable that a loss has occurred and the loss or range of loss can be reasonably estimated, a liability is recognized in the financial statements. The recognition of contingent losses for tax uncertainties requires management to make significant assumptions about the expected outcomes of certain tax contingencies. See Note 13 to our consolidated financial statements for information about our adoption of FIN 48.

Effect if Different Assumptions Used. The ultimate utilization of our remaining NOLs will depend on several factors, including our future financial performance and certain tax elections. Specifically, our utilization of NOLs will be affected by whether we elect NOL treatment under Internal Revenue Code Section (§) 382(l)(5) or § 382(l)(6). We currently anticipate that the treatment under § 382(l)(5) of the Internal Revenue Code will apply to Mirant going forward. Under that treatment, Mirant would have use of its NOLs as long as there is not a change of ownership (broadly defined as 50 percent change of five percent shareholders) within two years of emergence from bankruptcy. The § 382(l)(5) treatment requires us to reduce our NOLs by 1.1 billion due to interest accrued on debt settled with stock for the three years prior to emergence. Under § 382(l)(6), we would be subject to an annual limitation on use of NOLs. We will make the § 382(l)(5) or § 382(l)(6) election in our 2006 annual tax return to be filed in 2007. Given the likelihood that we will elect under 382 (l)(5) we have adjusted various deferred income tax items including the NOLs.

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 involves 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 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 Item 3. Legal Proceedings and Note 23 to our consolidated financial statements 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.

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

We are exposed to market risks associated with commodity prices, interest rates, credit risk and, to a lesser extent, foreign currency exchange rates.

Commodity Price Risk

In connection with our power generation business in the United States, we are exposed to energy commodity price risk associated with the acquisition of fuel needed to generate electricity, as well as the electricity produced and sold. A portion of our fuel requirements is purchased in the spot market and a portion of the electricity we produce is sold in the spot market. In addition, the open positions in our proprietary trading activities expose us to risks associated with changes in energy commodity prices. As a result, our financial performance in the United States varies depending on changes in the prices of energy and energy-related commodities. See Critical Accounting Policies and Estimates for a discussion of the accounting treatment for proprietary trading and asset management activities.

The financial performance of our power generation business is influenced by the difference between the variable cost of converting a source 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 price risk management 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 generation 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 generation facility widening or narrowing (or becoming negative) over time.

Through our asset management activities, we enter into a variety of exchange-traded and OTC energy and energy-related derivative contracts, such as forward contracts, futures contracts, option contracts and financial swap agreements to manage our exposure to commodity price risk and changes in conversion spreads. These derivatives have varying terms and durations, or tenors, which range from a few days to a number of 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.

Derivative energy contracts required to be reflected at fair value are presented as price risk management assets and liabilities in the accompanying consolidated balance sheets. The net changes in their market values are recognized in income in the period of change. The fair value of the power purchase agreements which we account for as derivatives are included in price risk management assets and liabilities on the accompanying consolidated balance sheets at December 31, 2006 and 2005. For a discussion of the litigation involving the Back-to-Back Agreement, see Note 23 to the consolidated financial statements. 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 and contracts.

The volumetric weighted average maturity, or weighted average tenor, of the price risk management portfolio, excluding the Back-to-Back Agreement, at December 31, 2006, was eleven months. The net notional amount, or net short position, of the price risk management assets and liabilities, excluding the Back-to-Back Agreement, at December 31, 2006, was approximately 24 million equivalent MWh.

The following table provides a summary of the factors affecting the change in net fair value of the price risk management asset and (liability) accounts in 2006 (in millions):

	Proprietary Trading	Asset Management	Back-to-Back Agreement	Total
Net fair value of portfolio at December 31, 2005	$ 41	$ (188)	$ (443)	$ (590)
Gains (Losses) recognized in the period, net	29	412	(8)	433
Contracts settled during the period, net	(23)	219	26	222
Back-to-Back Agreement				
Net fair value of portfolio at December 31, 2006	$ 47	$ 443	$ (425)	$ 65

The fair values of our price risk management assets and liabilities, net of credit reserves, as of December 31, 2006, are as follows (in millions):

	Net Price Risk Management Assets		Liabilities		Net Fair Value at
	Current	Noncurrent	Current	Noncurrent	December 31, 2006
Electricity	$ 603	$ 99	$ (247)	$ (8)	$ 447
Back-to-Back Agreement			(36)	(389)	(425)
Natural Gas	21	1	(26)	(2)	(6)
Oil	83		(10)	(29)	44
Coal	13		(3)		10
Other, including credit reserve	(5)				(5)
Total	$ 715	$ 100	$ (322)	$ (428)	$ 65

The following table represents the net price risk management assets and liabilities by tenor as of December 31, 2006 (in millions):

	Back-to-Back Agreement	All Other Agreements
2007	$ (36)	$ 429
2008	(31)	13
2009	(30)	40
2010	(36)	9
Thereafter	(292)	(1)
Net (liabilities) assets	$ (425)	$ 490

Value at Risk

Our Risk Management Policy prohibits the trading of certain products, e.g., natural gas liquids and pulp and paper and contains limits and restrictions related to our asset management and proprietary trading 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 in nature. To ensure compliance with this restriction, each transaction is classified as either a conversion spread transaction or fuel oil management transaction. Each conversion spread transaction is tested at the transaction level to ensure that each individual transaction executed is risk reducing relative to the overall asset position. Fuel oil management activities include management of physical fuel oil burns, physical fuel oil infrastructure and time and product spread positions. While these fuel oil activities are designed primarily to manage the risk associated with physical specifications and availability of fuel oil for the power plants, at any given time the fuel oil portfolio contains open market price risk. Each individual fuel oil transaction is not tested for risk reduction, but these activities are tested in aggregate to ensure that the overall activity is risk reducing. While the net result of these transactions is risk reducing, the timing of the roll-off could result in volatility in the gross margin results. To ensure that fuel oil management activities are risk-reducing in aggregate, a VaR limit of $5 million was established in the Risk Management Policy effective December 14, 2006.

The average VaR of our fuel oil management activities, using a five day holding period and a 95% confidence interval, was $2 million for the year ended December 31, 2006, and the VaR at December 31, 2006 was $2 million. If we assumed VaR levels using a one-day holding period for all positions in our fuel oil management portfolio, based on a 95% confidence interval, our average portfolio VaR for the year ended December 31, 2006 was $1 million and the VaR at December 31, 2006, was $1 million. This VaR control was initiated on December 14, 2006, and actual daily loss versus one-day VaR calculations are not available for the calendar year.

Our Risk Management Policy sets a VaR limit with respect to our proprietary trading activities of $7.5 million. See Critical Accounting Policies and Estimates for accounting treatment for asset management and proprietary trading activities.

The average VaR for our proprietary trading activities, using a five-day holding period and a 95% confidence level, was $3 million for the year ended December 31, 2006, and the VaR at December 31, 2006, was $4 million. If we assumed VaR levels using a one-day holding period for all positions in our proprietary trading portfolio, based on a 95% confidence level, our average portfolio VaR for the year ended December 31, 2006, was $1 million and the VaR at December 31, 2006, was $2 million. During the year ended December 31, 2006, the actual daily loss on a fair value basis exceeded the corresponding one-day VaR calculation 14 times, which is reasonable given our 95% confidence level.

Interest Rate Risk

We have several loans that provide for a variable rate of interest. Interest expense on such borrowings is sensitive to changes in the market rate of interest.

Our total debt from continuing operations is subject to variable interest rates through either the Mirant North America Term Loan or Revolving credit facility, assuming they are fully drawn, is approximately $1.5 billion. Our total debt recorded in liabilities held for sale subject to variable interest rates on term loans is approximately $144 million. A 1% per annum increase in the average market rate would result in an increase in our annual interest expense of approximately $15 million for continuing operations and $2 million for discontinued operations.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty failed to perform under its contractual obligations. We have established controls and procedures in our Risk Management Policy to determine and monitor the creditworthiness of customers and counterparties. Our credit policies are established and monitored by the Risk Oversight Committee. The Risk Oversight Committee includes the Chief Financial Officer and management s representatives from several functional areas. We measure credit risk as the loss we would record if our customers failed to perform pursuant to the terms of their contractual obligations less the value of collateral held by us, if any, to cover such losses. We use published ratings of customers, as well as our internal analysis, to guide us in the process of setting credit levels, risk limits and contractual arrangements including master netting agreements. Where external ratings are not available, we rely on our internal assessments of customers.

Collection Risk

Once we bill a customer for the commodity delivered 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 allowance for bad debts. We manage this risk using the same techniques and processes used in credit risk discussed above.

Foreign Currency Risk

From time to time, we have used currency swaps and currency forwards to hedge our net investments in certain foreign subsidiaries. Gains or losses on these derivatives are designated as hedges of net investments and are offset against the foreign currency translation gains or losses recorded in OCI relating to these investments. Occasionally, we use currency forwards to offset the effect of exchange rate fluctuations on forecasted transactions denominated in a foreign currency. We did not have any foreign exchange contracts outstanding at December 31, 2006, that are designated as hedges of our investments in foreign countries or otherwise.

Item 8. *Financial Statements and Supplementary Data*

MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2006	2005	2004
	(in millions, except per share data)		
Operating revenues	**$ 3,103**	$ 2,646	$ 3,248
Cost of fuel, electricity and other products	**1,156**	1,800	2,159
Gross Margin	**1,947**	846	1,089
Operating Expenses:			
Operations and maintenance	**609**	698	718
Depreciation and amortization	**137**	135	137
Impairment losses	**119**	9	9
Loss (gain) on sales of assets, net	**(49)**	17	49
Total operating expenses	**816**	859	913
Operating Income (Loss)	**1,131**	(13)	176
Other Expense (Income), net:			
Interest expense	**289**	1,404	18
Gain on sales of investments, net	**(76)**	(45)	
Interest income	**(76)**	(9)	(2)
Other, net	**(38)**	63	(66)
Total other expense (income), net	**99**	1,413	(50)
Income (Loss) From Continuing Operations Before Reorganization Items, Income Taxes	**1,032**	(1,426)	226
Reorganization items, net	**(163)**	(18)	227
Provision (Benefit) for income taxes	**(578)**	(18)	(2)
Income (Loss) From Continuing Operations	**1,773**	(1,390)	1
Income (Loss) From Discontinued Operations, net	**91**	99	(477)
Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	**1,864**	(1,291)	(476)
Cumulative Effect of Changes in Accounting Principles		(16)	
Net Income (Loss)	**$ 1,864**	$ (1,307)	$ (476)
Basic EPS:			
Basic EPS from continuing operations	**$ 6.22**		
Basic EPS from discontinued operations	**0.32**		
Basic EPS	**$ 6.54**		
Diluted EPS:			
Diluted EPS from continuing operations	**$ 5.97**		
Diluted EPS from discontinued operations	**0.31**		
Diluted EPS	**$ 6.28**		
Average shares outstanding	**285**		
Effect of dilutive securities	**12**		
Average shares outstanding assuming dilution	**297**		

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

F-2

MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2006 (in millions)	2005
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 1,142**	$ 1,068
Funds on deposit	**235**	1,542
Receivables, net	**381**	589
Price risk management assets	**715**	602
Inventories	**288**	275
Prepaid expenses	**142**	142
Assets held for sale	**4,972**	5,584
Deferred income taxes	**110**	
Other		30
Total current assets	**7.985**	9,832
Property, Plant and Equipment, net	**2,212**	2,328
Noncurrent Assets:		
Intangible assets, net	**214**	225
Price risk management assets	**100**	115
Deferred income taxes	**660**	132
Prepaid rent	**218**	208
Other	**147**	72
Total noncurrent assets	**1,339**	752
Total Assets	**$ 11,536**	$ 12,912
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Current portion of long-term debt	**$ 142**	$ 3
Claims payable and estimated claims accrual	**28**	1,903
Accounts payable and accrued liabilities	**425**	582
Price risk management liabilities	**322**	849
Liabilities held for sale	**2,205**	2,075
Deferred income taxes	**49**	132
Accrued taxes and other	**88**	202
Total current liabilities	**3,259**	5,746
Noncurrent Liabilities:		
Long-term debt	**3,133**	2,579
Price risk management liabilities	**428**	458
Asset retirement obligations	**41**	34
Pension and post-retirement obligations	**204**	208
Other	**10**	13
Total noncurrent liabilities	**3,816**	3,292
Liabilities Subject to Compromise	**18**	18
Commitments and Contingencies		
Stockholders Equity:		
Preferred stock, par value $.01 per share; authorized 100,000,000 in 2006 issued and 0 outstanding		
Common stock, par value $.01 per share, authorized 1.5 billion shares, issued 300,200,197 and 300,000,000 at December 31, 2006 and December 31, 2005, respectively, and outstanding 256,017,187 shares and 300,000,000 at December 31, 2006 and December 31, 2005, respectively	**3**	3
Treasury stock, at cost 44,183,010 shares and 0 shares at December 31, 2006 and December 31, 2005, respectively	**(1,261)**	
Additional paid-in capital	**11,317**	11,298
Accumulated deficit	**(5,598)**	(7,462)
Accumulated other comprehensive income	**(18)**	17
Total stockholders equity	**4,443**	3,856
Total Liabilities and Stockholders Equity	**$ 11,536**	$ 12,912

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

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, 2003	$ 4	$ (2)	$ 4,918	$ (5,679)	$ (64)
Net loss				(476)	
Other comprehensive income					(19)
Balance, December 31, 2004	4	(2)	4,918	(6,155)	(83)
Net loss				(1,307)	
Cancellation of pre-reorganization common stock	(4)	2	(4,918)		
Issuance of post-reorganization common stock	3		11,298		
Other comprehensive loss					100
Balance, December 31, 2005	3		11,298	(7,462)	17
Net income				1,864	
Stock repurchase		(1,261)			
Stock-based compensation			17		
Exercise of warrants			2		
Other comprehensive income					(25)
Adoption of SFAS No. 158, net of tax					(10)
Balance, December 31, 2006	**$ 3**	**$ (1,261)**	**$ 11,317**	**$ (5,598)**	**$ (18)**

MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Net Income (Loss)	**$ 1,864**	$ (1,307)	$ (476)
Other comprehensive income (loss), net of tax			
Cumulative translation adjustment	**2**	74	(17)
Unrealized gains on available-for-sale securities	**(27)**	27	
Reclassification of investment unrealized gains to earnings			(7)
Unrealized gain on investments			5
Other		(1)	
Other comprehensive income (loss), net of tax	**(25)**	100	(19)
Total Comprehensive Income (Loss)	**$ 1,839**	$ (1,207)	$ (495)

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

MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 2006 (in millions)	2005	2004
Cash Flows from Operating Activities:			
Net income (loss)	**$ 1,864**	**$ (1,307)**	$ (476)
Income (loss) from discontinued operations	**91**	99	(477)
Income (loss) from continuing operations	**1,773**	(1,406)	1
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:			
Amortization of transition power agreements and other obligations		(9)	(344)
Depreciation and amortization	**147**	148	146
Impairment losses	**119**	9	9
Cumulative effect of changes in accounting principles		16	
Non-cash post-petition interest expense		1,374	
Loss (gain) on sales of assets and investments	**(125)**	(28)	49
Non-cash reorganization items	**1**	26	123
Price risk management activities, net	**(655)**	16	(168)
Effect of the Plan of Reorganization		(285)	
Deferred income taxes	**(580)**	(4)	18
Stock-based compensation	**17**		
Non-cash gain on property tax settlement	**(71)**		
Other, net	**(34)**	27	(3)
Changes in operating assets and liabilities:			
Receivables, net	**218**	(271)	220
Other current assets	**346**	(431)	(111)
Other assets	**(70)**	(22)	(1)
Accounts payable and accrued liabilities	**(203)**	377	(183)
Settlement of claims payable	**(814)**		
Accrued taxes	**59**	65	16
Other liabilities	**(9)**	13	(13)
Total adjustments	**(1,654)**	1,021	(242)
Net cash provided by (used in) operating activities of continuing operations	**119**	(385)	(241)
Net cash provided by operating activities of discontinued operations	**444**	418	312
Net cash provided by operating activities	**563**	33	71
Cash Flows from Investing Activities:			
Capital expenditures	**(133)**	(101)	(90)
Proceeds from the sales of assets and other investments	**143**	165	45
Other investing activities	**1**		(11)
Net cash provided by (used in) investing activities of continuing operations	**11**	64	(56)
Net cash provided by (used in) investing activities of discontinued operations	**(163)**	15	(90)
Net cash provided by (used in) investing activities	**(152)**	79	(146)
Cash Flows from Financing Activities:			
Proceeds from issuance of long-term debt	**2,017**	100	318
Repayment of long-term debt	**(475)**	(2)	(2)
Settlement of debt under the Plan	**(990)**		
Debt issuance cost	**(51)**		
Proceeds from the exercise of warrants	**2**		
Stock repurchases	**(1,261)**		
Other		(1)	
Net cash provided by (used in) financing activities of continuing operations	**(758)**	97	316
Net cash provided by (used in) financing activities of discontinued operations.	**181**	(142)	(343)
Net cash used in financing activities	**(577)**	(45)	(27)
Effects of exchange rate changes from discontinued operations		(1)	
Net Increase (Decrease) in Cash and Cash Equivalents	**(166)**	66	(102)
Cash and Cash Equivalents, beginning of period	**1,068**	1,003	1,176
Plus: Cash and Cash Equivalents included in assets held for sale at beginning of year	**483**	482	411
Less: Cash and Cash Equivalents included in assets held for sale at end of year	**243**	483	482
Cash and Cash Equivalents, end of period	**$ 1,142**	$ 1,068	$ 1,003
Supplemental Cash Flow Disclosures:			
Cash paid for interest, net of amounts capitalized	**$ 372**	$ 120	$ 117
Cash paid for income taxes	**$ 165**	$ 68	$ 42
Cash paid for claims and professional fees from bankruptcy	**$ 1,908**	$ 171	$ 107

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

MIRANT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2006, 2005 and 2004

1. Description of Business and Organization

Mirant generates revenues primarily through the production of electricity in the United States, the Philippines and the Caribbean. As of December 31, 2006, the Company owned or leased 17,522 MW of electric generating capacity. 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 certain of its U.S. natural gas-fired plants (3,619 MW). See Note 3 for additional information regarding the treatment of these businesses and assets as discontinued operations as a result of this decision. Mirant s continuing operations of 10,650 MW consist of the ownership, long-term lease and operation of power generation facilities located in markets in the Mid-Atlantic and Northeast regions of the United States and in California, and energy trading and marketing operations in Atlanta, GA.

Mirant Corporation was incorporated in Delaware on September 23, 2005, and is the successor to a corporation of the same name that was formed in Delaware on April 3, 1993. This succession occurred by virtue of the transfer of substantially all of Old Mirant s assets to New Mirant in conjunction with Mirant s emergence from bankruptcy protection on January 3, 2006. Old Mirant was then renamed and transferred to a trust that is not affiliated with new Mirant. New Mirant serves as the corporate parent of the business enterprise and, pursuant to the Plan of Reorganization (the Plan) that was approved in connection with Old Mirant s emergence from bankruptcy, has no successor liability for any unassumed obligations of Old Mirant. See Note 12 for additional information related to Mirant s bankruptcy.

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.

The accompanying financial statements include the accounts of Mirant and its wholly-owned and controlled majority-owned subsidiaries as well as variable interest entities 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. Investments in minority-owned companies in which Mirant exercises significant influence over operating and financial policies are accounted for using the equity method of accounting. Jointly owned affiliates which Mirant does not control, as well as interests in variable interest entities in which Mirant is not the primary beneficiary, also are accounted for using the equity method of accounting.

All amounts are presented in U.S. dollars unless otherwise noted. In accordance with SFAS No. 144, the results of operations of the Company s businesses and assets to be disposed of have been reclassified to discontinued operations and the associated assets and liabilities have been reclassified to assets and liabilities held for sale for all periods presented. In addition, the accompanying consolidated statements of cash flows present the cash flows from discontinued operations in each of the three major categories (operating, investing and financing activities). The consolidated statements of cash flows for the years ended December 31, 2005 and 2004, were revised to conform to this presentation. See Note 3 for additional information regarding 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 and 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;
- determining the value of Mirant s asset retirement obligations;
- estimating future cash flows in determining impairments of long-lived assets, goodwill and indefinite-lived intangible assets;
- estimating the expected return on plan assets, rate of compensation increases and other actuarial assumptions used in estimating pension and other postretirement benefit plan liabilities; and
- estimating losses to be recorded for contingent liabilities.

Revenue Recognition

Mirant recognizes generation revenue from the sale of energy and recognizes integrated utilities and distribution revenue from the sale and distribution of energy when earned and collection is probable. The Company recognizes revenue when electric power is delivered to a customer pursuant to contractual commitments that specify volume, price and delivery requirements. Some sales of energy are based on economic dispatch, or as-ordered by an ISO, based on member participation agreements, but without an underlying contractual commitment. ISO 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. 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 plant, 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 units is normally recorded as capacity revenue and included in generation revenues in the consolidated statements of operations.

Derivative Financial Instruments

Derivative financial instruments are recorded in the accompanying consolidated balance sheets at fair value as either assets or liabilities, and changes in fair value are recognized currently in earnings, unless specific hedge accounting criteria are met. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized currently in earnings. If the derivative is designated as a cash flow hedge, the changes in the fair value of the derivative are recorded in OCI and the realized gains and losses related to these derivatives are recognized in earnings in the same period as the settlement of the underlying hedged transaction. The assets and liabilities related to derivative instruments that have not been designated as hedges for accounting purposes are included in price risk management assets and liabilities. For the years ended December 31, 2006, 2005 and 2004, the Company did not have any derivative 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 or proprietary trading. All derivative contracts are recorded at fair value, except for a limited number of transactions that qualify for the normal purchases or normal sales exclusion from SFAS No.133 and therefore qualify for the use of accrual accounting.

As the Company s commodity derivative financial instruments have not been designated as hedges for accounting purposes, changes in such instruments fair values are recognized currently in earnings. For asset management activities, changes in fair value of electricity derivative financial instruments are reflected in generation revenue and changes in fair value of fuel derivative contracts 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 contracts for proprietary trading activities are recorded as generation revenue in the accompanying consolidated statements of operations.

Concentration of Revenues

In 2006, 2005 and 2004, Mirant earned a significant portion of its operating revenue and gross margin from the PJM energy market, where its Mirant Mid-Atlantic generation facilities are located. Mirant Mid-Atlantic s revenues and gross margins as a percentage of Mirant s total revenues and gross margin from continuing operations are as follows:

	Years Ended December 31,		
	2006	2005	2004
Revenues	61 %	45 %	31 %
Gross margins	68 %	54 %	46 %

Concentration of Labor Subject to Collective Bargaining Agreements

As of December 31, 2006, approximately 18% and 32% of the employees at locations in the Company s continuing operations and discontinued operations, respectively, are subject to collective bargaining agreements. Approximately 31% of the employees at locations in the Company s discontinued operations are covered by collective bargaining agreements that have expired or will expire within one year.

Cash and Cash Equivalents

Mirant considers all short-term investments with an original maturity of three months or less to be cash equivalents.

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. As of December 31, 2006, current and noncurrent funds on deposit are $235 million and $6 million, respectively. As of December 31, 2005, current and noncurrent funds on deposit are $1.5 billion and $5 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 a $200 million deposit Mirant North America posted under its senior secured term loan to support the issuance of letters of credit. In addition, as of December 31, 2005, restricted cash included $853 million of escrowed proceeds from a bond offering in December 2005. These amounts were released from escrow on January 3, 2006.

Inventory

Inventory consists primarily of oil, coal, purchased emissions allowances and materials and supplies. Inventory, including commodity trading 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.

Emissions Allowances

Purchased emissions allowances are recorded in inventory at the lower of cost or market. Cost is computed on an average cost basis. Purchased emissions allowances for SO2 and NOx 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.

Emissions allowances granted by the EPA related to generation facilities owned by the Company are recorded at fair value at the date of the acquisition of the facility and are included in property, plant and equipment. These emissions allowances are depreciated on a straight-line basis over the estimated useful life of the respective generation facility, which ranges from 8 to 40 years, and are charged to depreciation and amortization expense in the accompanying consolidated statements of operations.

Emissions allowances granted by the EPA related to generation facilities leased by the Company are recorded at fair value at the commencement of the lease in other intangible assets. These emissions allowances are amortized on a straight-line basis over the term of the lease, and are charged to depreciation and amortization expense in the accompanying consolidated statements of operations. In addition the Company acquired emissions allowances for future periods as part of the California Settlement agreement. These allowances are included in other intangible assets and will be amortized over the periods in which they may be utilized.

The Company has determined that certain exchanges of emissions allowances that the Company may periodically transact qualify as nonmonetary exchanges under SFAS No. 153.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost, which includes materials, labor, and 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 plant 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 the advanced stages of development and during the construction period. The Company determines which debt instruments represent a reasonable measure of the cost of financing construction assets in terms of interest cost 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. Upon commencement of commercial operations of the plant or project, capitalized interest, as a component of the total cost of the plant, is amortized over the estimated useful life of the plant. For the years ended December 31, 2006, 2005 and 2004, the Company incurred the following interest costs (in millions):

	Years Ended December 31,		
	2006	**2005**	**2004**
Total interest costs	$ 298	$ 1,404	$ 18
Capitalized and included in construction work in progress	(9)		
Interest expense	$ 289	$ 1,404	$ 18

In the third quarter of 2005, the Company determined that it was probable that contractual interest on liabilities subject to compromise from the Petition Date would be incurred for certain claims expected to be allowed under the Plan and, accordingly, recorded approximately $1.4 billion of interest expense in 2005 on liabilities subject to compromise.

Goodwill and Intangible Assets

Goodwill represents the excess of costs over the fair value of assets of businesses acquired. Goodwill and intangible assets acquired in a purchase business combination that are determined to have an indefinite useful life are not amortized, but instead tested for impairment at least annually. Intangible assets with definite useful lives are amortized on a straight-line basis over their respective useful lives ranging up to 40 years to their estimated residual values. A goodwill impairment occurs when the fair value of a reporting unit is less than its carrying value including goodwill. The amount of the impairment charge, if an impairment exists, is calculated as the difference between the implied fair value of the reporting unit goodwill and its carrying value. The Company performs an annual assessment of goodwill at October 31 and whenever contrary evidence exists as to the recoverability of goodwill. The fair value of the reporting unit is calculated using discounted cash flow techniques and assumptions as to business prospects using the best information available. The Company had approximately $6 million in goodwill at December 31, 2006, related to Mirant Grand Bahama, which is recorded in assets held for sale on the consolidated balance sheets.

Environmental Remediation Costs

Mirant accrues for costs associated with environmental remediation when such costs are probable and can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information develops or circumstances change. The cost of future expenditures for environmental remediation obligations are discounted to their present value.

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

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

SFAS No. 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. Future performance relating to the sale of the Philippine assets is the most compelling form of positive evidence considered by management in the determination of the future recoverability of a portion of its net deferred assets.

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 No. 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.

Cumulative Effect of Changes in Accounting Principles

The Company adopted FIN 47, effective December 31, 2005, related to the costs associated with conditional legal obligations to retire tangible, long-lived assets. Conditional asset retirement obligations are recorded at the fair value in the period in which they are incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its fair value and the capitalized costs are depreciated over the useful life of the related asset. For the year ended December 31, 2005, the Company recorded a charge as a cumulative effect of a change in accounting principle of approximately $16 million, net of tax, related to the adoption of this accounting standard.

Foreign Currency Translation

For international operations in which the Company considers the functional currency to be the local currency, the foreign currency is translated into U.S. dollars using exchange rates in effect at period end for assets and liabilities and average exchange rates during each reporting period for results of operations.

Adjustments resulting from translation of financial statements of foreign operations are reported in accumulated OCI. For international operations in which the Company considers the functional currency to be the U.S. dollar, transactions denominated in currencies other than the U.S. dollar are translated into U.S. dollars. Gains or (losses) on such transactions are recognized in earnings and amounted to $(71) million and $14 million in 2005 and 2004, respectively. There were no gains or losses on such transactions in 2006. The loss of $71 million in 2005 is primarily related to the legal liquidation of several of the Company s European subsidiaries in the fourth quarter of 2005. This liquidation resulted in the release of the foreign exchange translation adjustment from accumulated other comprehensive income for these entities.

Earnings (Loss) per Share

Earnings per share information for periods prior to 2006 have not been presented. The Company does not think that this information is relevant in any material respect for users of its financial statements. See Note 19 for further discussion.

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

Recently Adopted Accounting Standards

In December 2004, the FASB issued SFAS No. 123R, which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. Mirant adopted the provisions of SFAS No. 123R on January 1, 2006, using the modified prospective transition method. All awards that are granted, modified or settled after the date of adoption will be measured and accounted for in accordance with SFAS No. 123R, with no restatement of prior periods.

Under the modified prospective transition method, a company is required to recognize compensation cost for unvested awards that are outstanding on the effective date based on the fair value that the Company had originally estimated for purposes of preparing its SFAS No. 123 pro forma disclosures. Mirant s unvested awards of stock-based compensation at December 31, 2005, were cancelled pursuant to the Plan. Therefore, there was no cumulative effect recognized upon adoption of SFAS No. 123R. Pre-tax expense related to stock-based compensation was approximately $16 million and $1 million, respectively, related to service condition and performance condition awards for the year ended December 31, 2006. See Note 14 for additional information on the Company s stock-based compensation.

In September 2005, the FASB ratified EITF 04-13, which requires companies to account for certain purchases and sales of inventory with the same counterparty as a single transaction. The Company adopted EITF 04-13 on April 1, 2006. The application of EITF 04-13 has not had a material impact on Mirant s statement of operations, financial position or cash flows.

In April 2006, the FASB issued FSP FIN 46R-6. The variability that is considered in applying FIN 46R affects the determination of whether an entity is a VIE, which interests are variable interests in the entity and which party, if any, is the primary beneficiary of the VIE. According to FSP FIN 46R-6, the variability to be considered should be based on the nature of the risks of the entity and the purpose for which the entity was created. The guidance in FSP FIN 46R-6 is applicable prospectively to an entity at the time a company first becomes involved with such entity and is applicable to all entities previously required to be analyzed under FIN 46R when a reconsideration event has occurred beginning with the first reporting period after June 15, 2006. Retrospective application to the date of the initial application of FIN 46R is permitted but not required. The Company adopted FSP FIN 46R-6 on July 1, 2006, on a prospective basis. Upon adoption there was no material impact on the Company s statements of operations, financial position or cash flows.

On September 13, 2006, the SEC issued SAB No. 108, which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB No.108 provides that a registrant should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB No. 108 is effective for fiscal years ending on or after November 15, 2006. The adoption of SAB No. 108 had no material impact on the Company s statements of operations, financial position or cash flows.

On September 29, 2006, the FASB issued SFAS No. 158, which requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity or changes in unrestricted net assets of a not-for-profit organization. SFAS No. 158 also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions.

The Company adopted SFAS No. 158 on December 31, 2006, and recognized an increase in accounts payable and accrued liabilities and other noncurrent liabilities of $16 million related to its underfunded domestic defined benefit pension plans and underfunded domestic postretirement benefit plans. See Note 14 for additional information related to the pension and other postretirement benefit plans of the Company s continuing business. The Company also recognized an increase in other assets held for sale of $25 million and an increase in liabilities held for sale of $16 million related to the defined benefit pension plans and other postretirement benefit plans of its foreign subsidiaries. The net after tax impact of adopting SFAS No. 158 was a $10 million decrease in Other Comprehensive Income for the year ended December 31, 2006.

The requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year-end statement of financial position is effective for the fiscal years ending after December 15, 2008. The Company currently uses a September 30 measurement date each year and will transition to a fiscal year-end measurement date by December 31, 2008.

New Accounting Standards Not Yet Adopted

In February 2006, the FASB issued SFAS No. 155, which allows fair value measurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. SFAS No. 155 is effective for all financial instruments acquired, issued or subject to a re-measurement event beginning in the first fiscal year after September 15, 2006. At the date of adoption, any difference between the total carrying amount of the existing bifurcated hybrid financial instrument and the fair value of the combined hybrid financial instrument will be recognized as a cumulative effect adjustment to beginning retained earnings. The Company will adopt SFAS No. 155 on January 1, 2007. The adoption of SFAS No. 155 is not expected to have a material impact on the Company s statements of operations, financial position or cash flows.

In March 2006, the FASB issued SFAS No. 156, which requires all separately recognized servicing assets and servicing liabilities to be measured initially at fair value and permits, but does not require, an entity to measure subsequently those servicing assets or liabilities at fair value. SFAS No. 156 is effective at the beginning of the first fiscal year after September 15, 2006. The Company will adopt SFAS No. 156 on January 1, 2007. All requirements for recognition and initial measurement of servicing assets and servicing liabilities will be applied prospectively to transactions occurring after the adoption of this statement. The adoption of SFAS No. 156 is not expected to have a material impact on the Company s statements of operations, financial position or cash flows.

On July 13, 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return.

The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is recognition based on a determination of whether it is more-likely-than-not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority having full knowledge of all relevant information. The second step is to measure a tax position that meets the more-likely-than-not threshold. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company will adopt FIN 48 on January 1, 2007. Upon initial adoption, the provisions of FIN 48 will be applied to all tax positions. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized. The Company anticipates that the balance sheet reclassification to increase retained earnings and decrease liabilities as a result of adopting this standard is between $50 million and $125 million including discontinued operations.

On June 28, 2006, the FASB ratified the EITF s consensus reached on EITF 06-3, which relates to the income statement presentation of taxes collected from customers and remitted to government authorities. The Task Force affirmed as a consensus on this issue that the presentation of taxes on either a gross basis or a net basis within the scope of EITF 06-3 is an accounting policy decision that should be disclosed pursuant to APB 22. A company should disclose the amount of those taxes that is recognized on a gross basis in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The Company will adopt EITF 06-3 on January 1, 2007. The adoption of EITF 06-3 is not expected to have a material impact on the Company s statements of operations, financial position or cash flows.

On July 13, 2006, the FASB finalized FSP FAS 13-2, which addresses how a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction affects the accounting by a lessor for that lease. The Company will adopt FSP FAS 13-2 on January 1, 2007. The adoption of FSP FAS 13-2 is not expected to have a material impact on the Company s statements of operations, financial position or cash flows.

On September 8, 2006, the FASB issued FSP AUG AIR-1. FSP AUG AIR-1 permits the following methods for accounting for major maintenance activities: direct expense, built-in overhaul and deferral. It specifically prohibits accruing in advance for major maintenance. The guidance in FSP AUG AIR-1 is to be applied to the first fiscal year beginning after December 15, 2006. The Company will adopt FSP AUG AIR-1 on January 1, 2007. The adoption of FSP AUG AIR-1 is not expected to have a material impact on the Company s statements of operations, financial position or cash flows given that the Company currently uses the deferral or direct expense methods of accounting for major maintenance activities.

On September 15, 2006, the FASB issued SFAS No. 157, which establishes a framework for measuring fair value in GAAP and expands disclosure about fair value measurements. SFAS No. 157 requires 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 No. 157 is effective at the beginning of the first fiscal year after November 15, 2007. The Company will adopt SFAS No. 157 on January 1, 2008. At the date of adoption, the Company will evaluate the fair value of its assets and liabilities according to the hierarchy established by the FASB and present the required disclosures. It is also expected that the adoption of SFAS No. 157 will impact the measurement of certain liabilities to incorporate Mirant s own credit standing and the accounting for inception gains and losses currently being deferred under EITF 02-3. The net deferred inception gains and losses at December 31, 2006, were $1.1 million. The Company has not yet determined the impact of SFAS No. 157 on its statements of operations, financial position or cash flows.

On February 15, 2007, the FASB issued SFAS No. 159, which permits 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 No. 159 also requires companies with trading and available-for-sale securities to report the unrealized gains and losses for which the fair value option has been elected within earnings for the period presented. SFAS No. 159 is effective at the beginning of the first fiscal year after November 15, 2007. The Company will adopt SFAS No. 159 on January 1, 2008. The Company has not yet determined the impact of SFAS No. 159 on its statements of operations, financial position or cash flows.

3. Dispositions

Overview

Assets and liabilities held for sale includes discontinued operations and other assets that the Company expects to dispose of in the next year. In the third quarter of 2006, Mirant commenced auction processes to sell the Philippine and Caribbean businesses and six natural gas-fired intermediate and peaking plants totaling 3,619 MW comprised of Zeeland (903 MW), West Georgia (613 MW), Shady Hills (469 MW), Sugar Creek (561 MW), Bosque (546 MW) and Apex (527 MW).

On December 11, 2006, Mirant entered into a definitive purchase and sale agreement with a consortium of The Tokyo Electric Power Company, Incorporated and Marubeni Corporation for the sale of its Philippine business for a purchase price of $3.424 billion, plus a working capital adjustment at the closing. After the payment of related debt, which is estimated to be $642 million at the closing, the net proceeds to the Company are expected to be $3.121 billion after transaction costs. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions, and the return to operation of both units at the Sual facility.

On January 15, 2007, Mirant entered into a definitive purchase and sale agreement with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively LS Power), for the sale of the six natural gas-fired plants discussed above for a purchase price of $1.407 billion, which includes estimated working capital upon closing. After the payment of $83 million of related debt, the net proceeds to Mirant are expected to be $1.307 billion after transaction costs. The sale of the Zeeland and Bosque natural gas-fired plants is subject to the terms of the Mirant North America credit facilities and senior notes, including the provisions with respect to the use of the proceeds of such sales to repay amounts under the senior term loans and/or reinvest with the sale proceeds. The transaction is expected to close in the second quarter of 2007 after the satisfaction of certain customary conditions to closing. See Note 10 for additional information regarding restrictions on the proceeds from the sale of the gas assets.

The associated assets and liabilities for the Philippine and Caribbean businesses and the six natural gas-fired intermediate and peaking plants have been reclassified to assets and liabilities held for sale in the consolidated balance sheets.

The table below presents the components of the balance sheet accounts classified as assets and liabilities held for sale for the years ended December 31, 2006 and 2005 (in millions):

	At December 31, 2006	At December 31, 2005
Current Assets:		
Cash and Cash Equivalents	$ 243	$ 483
Funds on Deposit	126	187
Other Current Assets	520	502
Total Current Assets	889	1,172
Property, Plant and Equipment, net	3,478	3,687
Noncurrent Assets:		
Investments	224	227
Other Noncurrent Assets	381	498
Total Noncurrent Assets	605	725
Total Assets	$ 4,972	$ 5,584
Current Liabilities:		
Short-term Debt	$ 25	$ 32
Current Portion of Long-term Debt	166	391
Other Current Liabilities	235	282
Total Current Liabilities	426	705
Noncurrent Liabilities:		
Long-term Debt	1,149	728
Other Noncurrent Liabilities	630	642
Total Noncurrent Liabilities	1,779	1,370
Total Liabilities	$ 2,205	$ 2,075

Assets held for sale at December 31, 2006, consisted of the planned dispositions discussed above. Assets held for sale at December 31, 2005, consisted of the planned dispositions plus $11 million related to the Mirant Service Center in Maryland and the Wichita Falls facility. The sale of both facilities closed in the second quarter of 2006, and the Company recognized a gain of approximately $6 million on the sale of the Mirant Service Center. The Company recognized a loss of $11 million in the fourth quarter of 2005 related to the sale of Wichita Falls and recognized no additional gain or loss upon completion of the sale.

Variable Interest Entities

The Company has held a minority equity interest in Ilijan, a non-consolidated VIE, since July 2000. The non-consolidated VIE primarily holds an interest in a generation facility and has total assets of approximately $129 million and $116 million at December 31, 2006 and 2005, respectively. It is the Company s view that its maximum exposure to loss associated with its interest in the non-consolidated VIE is the Company s carrying value of its investment in the VIE at December 31, 2006, of approximately $63 million. The Company s investment in Ilijan is included in the Philippine business, which is subject to a definitive purchase and sale agreement.

Jamaica Public Service Company Limited, an 80% owned subsidiary of the Company, purchases power under PPAs, including PPAs with JPPC and JEP. The sole purpose of JPPC and JEP is to generate power to be sold to Jamaica Public Service Company Limited. The Company has no voting or equity interest in either JPPC or JEP. JPPC owns a 60 MW power facility and sells electricity to Jamaica Public

Service Company Limited under a PPA through August 2016. The Company had accounted for the PPA with JPPC as a capital lease since its March 2001 acquisition of Jamaica Public Service Company Limited. JEP owns a 119 MW floating power facility and sells electricity to Jamaica Public Service Company Limited under a PPA through February 2026. In March 2006, Jamaica Public Service Company Limited renegotiated an existing 70 MW PPA with JEP to add an additional 49 MW and to extend the term of the PPA through February 2026. The Company had accounted for the PPA with JEP as a capital lease since its March 2006 amendment of the lease and as an operating lease prior to that amendment.

During the third quarter of 2006, the Company reevaluated its PPAs with JPPC and JEP based on evolving interpretations of FIN 46*,* as amended. As a result of this reevaluation, the Company now consolidates JPPC and JEP because they are determined to be VIEs, whereby the Company is considered the primary beneficiary. JPPC and JEP have total assets of $118 million and $141 million, respectively, at December 31, 2006. As a result of the consolidation of JPPC and JEP, the Company recorded an increase in assets held for sale of $86 million and an increase in liabilities held for sale of $86 million.

Long-Term Debt

Long-term debt recorded in liabilities held for sale at December 31, 2006 and 2005, is as follows (in millions):

	At December 31, 2006	At December 31, 2005	Interest Rate	Secured/ Unsecured
Long-term Debt:				
Mirant North America:				
Mirant Zeeland capital lease, due 2007 to 2012	$ 11	$ 11	9.5%	
Other:				
Mirant Sweden International AB (publ), due 2007 to 2012	700		LIBOR + 2.25%	Secured
Mirant Pagbilao project loan, due 2006 to 2007		99	LIBOR + 2.15% to 10.25%	Secured
Mirant Sual project loan, due 2006 to 2012		452	5.95% to 10.56%	Secured
Jamaica Public Service Company Limited, due 2007 to 2030	169	230	7.00% to LIBOR + 7.5%	Secured
Jamaica Public Service Company Limited, due 2016	180		11%	Unsecured
Mirant Grand Bahama Limited, due 2007 to 2011	10	12	LIBOR + 1.25%	Secured
Grand Bahama Power Company Limited, due 2007 to 2014	50	43	5.625% to Bahamian Prime + 1.125%	Unsecured
Mirant Trinidad Investments LLC, due 2016	100	73	7.017%	Secured
Mirant Curacao Investments, Ltd, due 2007	12	14	10.15%	Secured
West Georgia Generating Company, due 2007 to 2011	83	95	LIBOR + 3.125%	Secured
Mirant Curacao Investments deferred acquisition price, due 2006		3	9.00%	Unsecured
Jamaica Public Service Company Limited capital lease, due 2006 to 2016		87	12.51%	
Total long-term debt	1,315	1,119		
Less: current portion of long-term debt	(166)	(391)		
Total long-term debt, excluding current portion	$ 1,149	$ 728		

Mirant Asia-Pacific Loan Facility. On August 15, 2006, Mirant Sweden International AB (publ), as borrower, and Mirant Asia-Pacific Limited (together with certain of its subsidiaries), as guarantor, completed the funding of its Mirant Asia-Pacific Loan Facility for Mirant s Philippine business. The Mirant Asia-Pacific Loan Facility has a maturity date six years from the date of the drawing. Interest on the Mirant Asia-Pacific Loan Facility is payable at a rate per annum equal to the U.S. Dollar LIBOR determined for certain interest periods plus an applicable margin set at 2.25% per annum. In connection with the completion of the funding under this facility, the Company repaid $402 million of existing debt at Pagbilao and Sual. A portion of these funds, together with other funds from the Philippine business were distributed or repaid to Mirant Corporation and were used as part of the consideration for Mirant s modified Dutch Auction share repurchase announced on July 11, 2006.

The payment obligations of Mirant Sweden International AB (publ) under the Mirant Asia-Pacific Loan Facility are unconditionally guaranteed by Mirant Asia-Pacific Limited and certain of its direct and indirect subsidiaries, referred to as the subsidiary guarantors , under a guaranty agreement and will constitute senior, secured obligations of the subsidiary guarantors. In connection with the sale of the Philippine business, the Company expects that the Mirant Asia-Pacific Loan Facility will be repaid.

Jamaica Public Service Company Notes. On July 6, 2006, Mirant JPS Finance, a wholly-owned subsidiary of Mirant, issued senior notes in an aggregate principal amount of $180 million that bear interest at 11% and mature on July 6, 2016. Mirant JPS Finance deposited the gross offering proceeds into an escrow account for the benefit of the holders of the notes. After the satisfaction of specified conditions and in connection with the repayment of Jamaica Public Service Company s credit facilities with Royal Bank of Trinidad and Tobago Limited, on August 31, 2006, Jamaica Public Service Company Limited assumed all of Mirant JPS Finance s obligations under the notes in exchange for the release of the offering proceeds from the escrow account. Interest on the notes is payable semiannually. Prior to the assumption of notes by Jamaica Public Service Company Limited, the notes were general unsubordinated obligations of Mirant JPS Finance secured by the escrow funds. Upon the assumption of the notes by Jamaica Public Service Company Limited, the notes are general unsecured obligations of Jamaica Public Service Company Limited without recourse to any other Mirant entity. In 2006, Jamaica Public Service Company Limited repaid $186 million of long-term debt. Upon the sale of Jamaica Public Service Company Limited, they will be required to make an offer to purchase such notes at a price equal to 101% of the principal amount thereof; provided, however, that Jamaica Public Service Company will not be required to make such an offer if a third-party makes an offer to purchase such notes on the same terms and purchases all notes validly rendered pursuant to such offer.

On December 18, 2006, Jamaica Public Service Company Limited repaid $20 million of maturing short-term debt and issued $15 million of new short-term debt. The $15 million note has an interest rate equal to 12-month LIBOR plus 3% with interest payable on a quarterly basis. The maturity date is December 18, 2007.

Mirant Trinidad Investments, LLC Notes. During the first quarter of 2006, Mirant Trinidad Investments issued $100 million of 7.017% notes. Interest on the notes is payable semiannually, and the principal is due on February 1, 2016. A significant portion of the net proceeds of the offering were used by Mirant Trinidad Investments to repay its $73 million aggregate principal amount of 10.20% notes due January 31, 2006. The remaining net proceeds are being used by Mirant Trinidad Investments to finance a portion of a PowerGen expansion project. The notes are secured by a pledge and assignment by Mirant Trinidad Investments of its shares of common stock issued by PowerGen and by certain other collateral. The notes are solely the obligation of Mirant Trinidad Investments without recourse to any other Mirant entity or to PowerGen. In connection with the sale of Mirant Trinidad Investments, the holders of the notes will have the right to require Mirant Trinidad Investments to purchase all or a portion of such notes at a price equal to 101% of the principal amount thereof.

Mirant Grand Bahama Limited Credit Facility. In August 1996, Mirant Grand Bahama Limited entered into a $28 million senior secured credit facility. The outstanding balance of the facility was $12.4 million as of December 31, 2005, and was due to mature during 2006. During the first quarter of 2006, the term of the facility was extended to August 2011. The senior secured credit facility is an obligation of Mirant Grand Bahama Limited and is non recourse to any other Mirant entities. In connection with the sale of the Caribbean business, the Company expects that the senior secured credit facility will remain outstanding.

Other Commitments

Mirant has commitments under fuel and transportation, long term service agreements and other purchase commitments with various terms and expiration dates that are related to its discontinued operations. The total of these commitments as of December 31, 2006, approximate $555 million.

Measurement of Assets Held for Sale

In accordance with SFAS No. 144, an asset classified as held for sale shall be measured at the lower of carrying value or fair value less costs to sell. The fair value of the Philippine business and the six U.S. natural gas-fired plants was determined based upon the final sales price as specified in the respective executed purchase and sale agreements. As further explained below, Mirant is seeking to sell the Caribbean business as a whole and has determined that no impairment is necessary.

Philippines. Mirant has ownership interests in three generating facilities in the Philippines: Sual, Pagbilao and Ilijan. Its net ownership interest in these three generating facilities is approximately 2,203 MW. Pursuant to the definitive purchase and sale agreement entered into by Mirant with the consortium of The Tokyo Electric Power Company and Marubeni Corporation on December 11, 2006, Mirant will sell the Philippine business in a single transaction. Upon completion of the transaction, Mirant expects to record a pre-tax gain of approximately $2 billion.

Caribbean. Mirant s net ownership interest in the Caribbean business is 1,050 MW. The ownership includes controlling interests in two vertically integrated utilities: an 80% interest in Jamaica Public Service Company Limited and a 55% interest in Grand Bahama Power Company. Mirant also owns a 39% interest in PowerGen, a 26% interest in Curacao Utilities Company and a $40 million convertible preferred equity interest in Aqualectra, an integrated water and electric company in Curacao. Mirant is currently seeking to sell the Caribbean business in a single transaction. Mirant s analysis indicated that no impairment was necessary, as the estimated fair value less costs to sell exceeded the book carrying value. Mirant received non-binding indicative bids for the Caribbean assets in November. Based on a review of the bids, it remains more-likely-than-not that the Caribbean business will be sold in a single transaction. Mirant determined that no impairment was necessary in the fourth quarter as bids from potential buyers exceeded the carrying value of the assets.

U.S. Natural Gas-Fired Plants. Mirant entered into a definitive purchase and sale agreement with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively LS Power), to sell six U.S. natural gas-fired intermediate and peaking plants comprised of Zeeland, West Georgia, Shady Hills, Sugar Creek, Bosque and Apex on January 15, 2007. Pursuant to the definitive purchase sales agreement entered into by Mirant with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively LS Power), the six plants will be sold in a single transaction. The Company recorded an impairment loss of $396 million in the third quarter of 2006 to write down the assets to their estimated fair value less cost to sell. As a result of updated fair values along with changes to the working capital calculation in the draft purchase and sale agreement provided to the bidders, the Company recorded a reduction to the impairment loss of $21 million in the fourth quarter of 2006. The net 2006 impairment loss of $375 million was recorded in discontinued operations in the Company s consolidated statements of operations for the year ended December 31, 2006 to decrease the carrying value of the assets to their fair value less costs to sell.

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 or have met the required criteria for such classification at December 31, 2006.

In addition to the planned dispositions, discontinued operations includes previously completed sales of asset groups. In the first quarter of 2006, Mirant executed an agreement to sell its 77 MW combined cycle Wichita Falls facility in Texas. The sale of the plant was completed on May 4, 2006. In the third quarter of 2005, the Company completed the sale of its Wrightsville generating facility to Arkansas Electric Cooperative Corporation for $85 million and recognized a net gain on sales of assets of $2 million.

In the second quarter of 2004, the Company recognized an impairment charge of $48 million related to its 50% interest in the Coyote Springs 2 project. In the fourth quarter of 2004, the Company entered into an agreement to sell its 50% interest to Avista Energy. In the first quarter of 2005, the Company completed the sale and received proceeds of $63 million and recognized no additional significant gain or loss on the transaction.

A summary of the operating results for these discontinued operations for the years ended December 31, 2006, 2005 and 2004 are as follows (in millions):

	Year Ended December 31, 2006			
	U.S.	Philippines	Caribbean	Total
Operating revenues	$ 287	$ 469	$ 825	$ 1,581
Operating expenses(1)	574	187	686	1,447
Operating income (loss)	(287)	282	139	134
Other expense (income), net(2)	9	(46)	80	43
Net income (loss)	$ (296)	$ 328	$ 59	$ 91

	Year Ended December 31, 2005			
	U.S.	Philippines	Caribbean	Total
Operating revenues	$ 323	$ 488	$ 729	$ 1,540
Operating expenses	298	195	623	1,116
Operating income	25	293	106	424
Other expense, net	102	179	44	325
Net income(loss)	$ (77)	$ 114	$ 62	$ 99

	Year Ended December 31, 2004			
	U.S.	Philippines	Caribbean	Total
Operating revenues	$ 278	$ 481	$ 564	$ 1,323
Operating expenses	322	758	493	1,573
Operating income (loss)	(44)	(277)	71	(250)
Other expense, net	56	128	43	227
Net income (loss)	$ (100)	$ (405)	$ 28	$ (477)

(1) Includes, for the year ended December 31, 2006, an impairment loss of $375 million in the U.S.

(2) Includes, for the year ended December 31, 2006, income tax benefits of $141 million and $124 million related to the Philippine disposition.

Contingencies

Sual Outages

Since July 12, 2006, Mirant Sual has had an unplanned outage of unit 2 of its generation facility due to a failure of the generator. The generator manufacturer has contracted to repair the unit 2 generator at a cost of approximately $17 million. The repairs to unit 2 are scheduled to be completed in March 2007. On October 23, 2006, unit 1 at the Sual generation facility had an unplanned outage also as a result of a failure of the generator. Mirant has contracted with the generator manufacturer to perform repairs to unit 1 at an approximate cost of $21 million, with repairs expected to be completed in May 2007. Mirant Sual expects to recover through insurance proceeds a substantial portion of the cost of the repairs of units 1 and 2 that exceeds Mirant Sual s deductible of $5 million per occurrence.

Mirant Sual has accumulated significant outage allowances under its energy conversion agreement with NPC. On January 11, 2007, Mirant Sual confirmed its agreement with NPC on the nominated capacity for the unused accumulated allowable outage periods through the contract year ended in October 2006

and also confirmed that the 55 allowable outage days per unit for the contract year beginning in October 2006 will be used upon the return to service of the respective units. In connection with the present outages, Mirant Sual expects to utilize accumulated allowable outage days and, thus, earn capacity fees, for unit 1 and unit 2 through April 5, 2007 and October 19, 2006, respectively. For the balance of the outage periods after utilization of the accumulated outage allowances under the energy conversion agreement, Mirant Sual will make claims under its business interruption insurance to compensate it for lost capacity and energy fees, subject to deductible periods.

The Company does not expect that, after taking into account the outage allowances under the energy conversion agreement and the expected insurance proceeds, the reduction in capacity payments and energy fees to it resulting from the outages will have a material impact on its consolidated results of operations or financial condition.

Finalizing the sale of the Philippine business is contingent upon Mirant s ability to return to operation both units at the Sual plant.

NPC Claims

Mirant Sual is contracted to sell 1,000 MW of its 1,218 MW capacity to NPC pursuant to an energy conversion agreement. Mirant Sual is entitled to sell the 218 MW of excess capacity to Mirant (Philippines) Energy Corporation, which markets the Sual excess capacity to customers agreed or otherwise approved by NPC through the energy supply business of Mirant (Philippines) Energy Corporation. Mirant (Philippines) Corporation received a letter from NPC dated March 16, 2006, claiming refunds in the amount of $26 million relating to sales of excess capacity from January 2001 to January 2006. Mirant (Philippines) Energy Corporation and NPC signed a Clarificatory Framework for Sual Power Plant on February 13, 2007, clarifying the dispatch protocol of the Sual excess sale and resolving or withdrawing the claims of NPC. In connection with such resolution, Mirant (Philippines) Energy Corporation paid $9 million to NPC.

Philippine Real Property Taxes

Real property taxes in the Philippines are levied by applying the tax rate to a locally determined taxable value of the property. Under the Philippine Local Government Code (LGC), the taxable value of property depends on the nature and use of the property. For land, machinery and equipment owned by commercial and industrial users, the taxable value of property is assessed at up to 80% of its fair market value. For land, machinery and equipment owned and used by government-owned or controlled corporations in the provision of certain services, including electricity generation, the taxable value is assessed at up to 10% of the fair market value of the property. The local taxing authorities in Pagbilao assess real property taxes for the Pagbilao generation facility at the 80% assessment level. The local taxing authorities in Sual currently assess real property taxes for the Sual generation facility at the 10% level. However, the local taxing authority in Sual may pass an ordinance or resolution applying an assessment level of up to 80% on future assessments.

Another provision of the LGC provides that machinery and equipment that are actually, directly or exclusively used by government-owned or controlled corporations engaged in the generation and transmission of electric power are exempt from real property taxes.

Under the energy conversion agreements for Pagbilao and Sual, which were executed under the Philippine government s BOT program, NPC is responsible for payment of real property taxes. NPC, a government-owned corporation, is the owner of the land on which the Pagbilao and Sual Plants are situated and historically has paid the real property tax on the land. Mirant s subsidiaries are currently the owners of record of the machinery, buildings and equipment constituting the Philippine plants. When the local taxing authorities in Pagbilao and Sual assessed property taxes on the Philippine plants, the Company referred the matter to NPC. NPC has taken the position that it is the beneficial owner of the machinery and equipment for purposes of the real property tax because it will own the Philippine plants when they are transferred to NPC pursuant to the energy conversion agreements. NPC has filed petitions for exemption with the relevant tax courts, claiming that it is exempt from real property taxes on the machinery and equipment that are used to generate electricity pursuant to the LGC.

In a case filed by NPC, the Philippine Court of Tax Appeals ruled that NPC is not exempt from real property taxes on machinery and equipment and cannot be treated as the owner of the machinery and equipment. Therefore, the machinery and equipment may be assessed at a taxable level of up to 80% of its fair market value. The case is now before the Philippine Supreme Court. Absent a binding injunction or restraining order preventing them from acting (such as the Philippine Supreme Court order discussed below), the local authorities would have the right to issue a notice of delinquency to Mirant Sual and Mirant Pagbilao as the record owners of the respective properties and, if the taxes were not paid, to levy against the Philippine plants. With respect to the Sual Plant, the local taxing authorities in Sual have assessed and been paid all taxes at the 10% level through December 31, 2005. In February 2006, Mirant Sual received an assessment in the amount of approximately $1.4 million representing the 2006 real property tax on the Sual Plant. Subsequently, Mirant Sual has received letters from the local taxing authority demanding payment of the assessed taxes with respect to machinery and equipment, including a final demand letter for the payment of 2006 assessed taxes in the amount of approximately $1.8 million. Mirant Sual forwarded the assessment and subsequent demand letters to NPC, which is responsible for paying the tax under its energy conversion agreement. On February 5, 2007, Mirant Sual sent a reply letter to the local taxing authority stating that there is a pending case in the local tax court where NPC, as actual direct, exclusive and beneficial owner of the plant is claiming exemption from the payment of real property taxes.

With respect to the Pagbilao Plant, the disputed tax assessments are approximately $85 million related to periods through December 31, 2006. On July 26, 2006, the Office of the Municipal Treasurer of the Municipality of Pagbilao, the Province of Quezon, delivered a Warrant of Levy to Mirant Pagbilao stating that Mirant Pagbilao is delinquent in the payment of real estate taxes and declaring the properties at the Pagbilao Plant are to be levied and sold at a public auction to satisfy the tax delinquency. Mirant Pagbilao referred the Warrant of Levy to NPC and sought an injunction against the Warrant of Levy and any attempted levy and auction of the Pagbilao facility from the Philippine Court of Appeals, the intermediate appeals court in the Philippines. Mirant Pagbilao s application remains pending before the Philippine Court of Appeals. Subsequently, in the case between NPC and the Pagbilao local government pending before the Philippine Supreme Court, and on application by NPC, the Philippine Supreme Court issued an order restraining the Pagbilao local government units and taxing authorities from executing and implementing the Warrant of Levy or any similar issuance with respect to the tax assessments on the Pagbilao Plant until the issuance of further orders from the Philippine Supreme Court. The outcome of this matter cannot be predicted, nor can there be any assurances that the Philippine Supreme Court will not subsequently lift its restraining order. However, if Mirant Pagbilao is held liable for payment of the real property taxes it shall seek full recovery from NPC or, in the event NPC does not pay, from the Government of the Philippines. Payment of NPC s obligations to Mirant Sual and Mirant Pagbilao under the energy conversion agreements is guaranteed by the Government of the Philippines.

In 2005, in order to provide assistance to the local governments while the real property tax matter was being reviewed by the Philippine courts and to avoid the possibility that the local governments might issue a notice of delinquency, Mirant subsidiaries entered into memoranda of agreement with the respective taxing authorities pursuant to which such authorities agreed not to take any actions in connection with real property taxes pending the judicial resolutions of the issue of availability of the claimed exemption by NPC. In connection with the memoranda of agreement, Mirant subsidiaries advanced $11 million to the local governments towards the disputed tax assessments. The Company may elect to make further advances until the matter is finally decided by the courts. Further, the Company intends to seek to recover these advances from NPC or from the local governments when the outcome of the dispute is decided by the Philippine Supreme Court.

4. Impairments on Assets Held and Used

In accordance with SFAS No. 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.

Current Year Events

The Mirant Lovett and Mirant Bowline generation facilities in New York have been subject to disputes with local tax authorities regarding property tax assessments. In addition, Mirant New York and Mirant Lovett entered into the 2003 Consent Decree to resolve issues related to NSR requirements under the Clean Air Act related to the Lovett plant. Mirant Lovett is in discussions with the NYSDEC and the New York State Office of the Attorney General regarding environmental controls under the 2003 Consent Decree.

On August 11, 2006, and August 28, 2006, the New York state court issued decisions addressing Mirant Bowline s challenges to the assessed values of the Bowline facility for the years 1995 to 2003 and Mirant Lovett s challenges to the assessed values of the Lovett facility for the years 2000 to 2003. Except for 1996, where it found that Mirant Bowline had failed to perfect its challenge to the assessed value of the Bowline facility, the New York state court concluded that the value of the Bowline facility and the Lovett facility in each year was substantially less than the assessed value set by the taxing authorities.

Under the 2003 Consent Decree, Mirant Lovett is required to make an election to install certain environmental controls on units 5 and 4 of the Lovett facility or shut down those units by April 30, 2007 and April 30, 2008, respectively. On September 19, 2006, Mirant Lovett sought Bankruptcy Court approval to discontinue operations at units 3 and 5 of the Lovett generation facility if an alternative environmental compliance mechanism that is agreeable to the State of New York is not approved by April 30, 2007. On October 18, 2006, the Bankruptcy Court approved the Company s request. On October 19, 2006, Mirant Lovett submitted notices of its intent to discontinue operations at units 3 and 5 of the Lovett facility on April 30, 2007, to the New York Public Service Commission, NYISO, Orange and Rockland and several other affected transmission and distribution utilities in New York. Mirant Lovett reserved its rights to withdraw these notices if a viable alternative environmental compliance mechanism is found. See New York State Administrative Claim in Note 23 Litigation and Other Contingencies for additional information.

On December 14, 2006, the Bankruptcy Court approved a settlement of disputed property taxes among Mirant Bowline, Mirant Lovett, Hudson Valley Gas and various New York tax jurisdictions. The settlement resolves pending disputes regarding refunds sought by the Company s New York subsidiaries for property taxes paid for 1995 through 2003 and unpaid taxes assessed for 2003 through 2006. Under the settlement, in February 2007, the Company received refunds totaling approximately $163 million for 1995 through 2002, and paid unpaid taxes of approximately $115 million for 2003 through 2006, resulting in receipt of a net cash amount of $48 million. As a result of the refunds and the reductions in unpaid taxes under the settlement, the Company recognized a gain of $244 million in the fourth quarter of 2006. Of this amount, $163 million was included in reorganization items, net in the consolidated statement of operations as it related to periods prior to the Petition Date.

Asset Grouping

For purposes of measuring an impairment loss, a long-lived asset or assets must be grouped at the lowest level of independent identifiable cash flows. All of the units at Mirant Lovett were viewed as one group. For Bowline, the Company determined that the suspended Bowline unit 3 construction project was independent of the operating Bowline units. In addition, the Company s analysis and planning around the operating Bowline units 1 and 2 did not consider the suspended construction project for Bowline unit 3.

Assumptions and Results

In its impairment analysis of the Bowline and Lovett generation facilities in prior periods, the Company assumed that PILOT agreements covering 2006 and seven subsequent years would be successfully approved and implemented. The Company no longer expects such PILOT agreements to be implemented. The August 2006 decisions and the appeals that followed prompted management to test for recoverability of the asset under SFAS No. 144 because additional uncertainty existed related to achieving property taxation levels that would allow economically feasible operation of the Bowline and Lovett generation facilities. As a result of these developments, management re-reviewed the economic viability of these facilities in the third quarter of 2006.

Lovett. The Company s assessment of Lovett under SFAS No. 144 in the third quarter of 2006 involved estimating property tax refunds and payments and assuming that property taxes would be negotiated to a reasonable level for future periods. Among the multiple scenarios considered were the shut down of units 3 and 5 by April 30, 2007, and unit 4 by April 30, 2008. The Company also considered scenarios that would allow operations past April 2008 because the Company continues to work with the State of New York and other parties to achieve a solution related to environmental controls and to allow Lovett to continue to contribute to the reliability of the electric system of the State of New York. The sum of the probability weighted undiscounted cash flows for the Lovett generation facility exceeded the Company s carrying value at September 30, 2006. As the refunds and taxes owed agreed upon in the settlement agreement were not materially different from the estimates used in the impairment analysis, the Company determined that no further analysis was needed at December 31, 2006.

Bowline Units 1 and 2. The Company s assessment of Bowline units 1 and 2 under SFAS No. 144 in the third quarter of 2006 involved estimating property tax refunds and payments and assuming that property taxes would be negotiated to levels for future periods that would allow Bowline units 1 and 2 to operate until the end of their remaining economic useful lives. The sum of the undiscounted cash flows exceeded the Company s carrying value at September 30, 2006, for Bowline units 1 and 2. As the refunds and taxes owed agreed upon in the settlement agreement were not materially different from the estimates used in the impairment analysis, the company determined that no further analysis was needed at December 31, 2006.

Bowline Unit 3. The Company s assessment of the Bowline unit 3 suspended construction project assumed that completion of this project was remote. A strategic review of the Company s portfolio of assets in 2006 resulted in the conclusion that the Bowline 3 project as currently configured and permitted is 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 by $120 million, which is reflected in impairment losses on the consolidated statements of operations for the year ended December 31, 2006. On January 15, 2007, the Company entered into a definitive purchase and sale agreement with a subsidiary of LS Power Equity Partners I, L.P., LS Power Equity Partners II, L.P. and certain other affiliated funds, (collectively LS Power), for the sale of six U.S. natural gas-fired assets, which includes some of the equipment at Bowline unit 3. The transaction is expected to close in the second quarter of 2007. The sale of the equipment at

Bowline unit 3 is subject to bankruptcy court approval. A hearing on the motion to sell the Bowline 3 equipment is scheduled for March 8, 2007.

5. Accounts Receivable and Notes Receivable

Receivables consisted of the following at December 31, 2006 and 2005 (in millions):

	At December 31, 2006	2005
Customer accounts	$ 316	$ 698
Notes receivable	20	4
Other	88	24
Less: allowance for uncollectibles	(32)	(110)
Total receivables	392	616
Less: long-term receivables included in other long-term assets	(11)	(27)
Total current receivables	$ 381	$ 589

6. Inventory

Inventory, at December 31, 2006 and 2005 consisted of (in millions):

	At December 31, 2006	2005
Fuel	$ 196	$ 202
Materials and supplies	63	58
Emissions allowances	29	15
Total inventory	$ 288	$ 275

7. Financial Instruments

Commodity Financial Instruments

The Company manages the risks around fuel supply and power to be generated from its physical asset positions. Mirant manages the price risk associated with asset management activities through a variety of methods. Mirant s Risk Management Policy requires that asset management activities are restricted to only those activities that are risk-reducing in nature. In addition, the Company, through its proprietary trading and fuel oil management activities, attempts to achieve incremental returns by entering into energy contracts where it has specific market expertise or physical asset positions. Proprietary trading and fuel oil management activities increase risk and expose the Company to risk of loss if prices move differently than expected. As of December 31, 2006, Mirant s Risk Management Policy sets VaR limits with respect to the Company s proprietary trading and fuel oil management activities of $7.5 million and $5 million, respectively.

Mirant enters into a variety of derivative financial and physical instruments to manage its exposure to the prices of the fuel it acquires for generating electricity, as well as the electricity that it sells. These include contractual agreements, such as forward purchase and sale agreements, futures, swaps and option contracts. Futures are traded on national exchanges and swaps are typically traded in OTC financial markets. Option contracts are traded on both a national exchange and in OTC financial markets. These contractual agreements have varying terms, notional amounts and durations, or tenors, which range from a few days to a number of years, depending on the instrument. As part of its proprietary trading activities, the Company is exposed to certain market risks in an effort to generate gains from changes in market prices by entering into derivative instruments, including exchange-traded and OTC contracts, as well as other contractual arrangements.

Derivative instruments are recorded at their estimated fair value in the Company s accompanying consolidated balance sheets as price risk management assets and liabilities except for a limited number of transactions that qualify for the normal purchase or normal sale exception election that allows accrual accounting treatment. Changes in the fair value and settlements of electricity derivative financial instruments are reflected in generation revenue and changes in the fair value and settlements of fuel derivative contracts are reflected in cost of fuel and other products in the accompanying consolidated statements of operations. As of December 31, 2006, the Company does not have any derivative instruments for which hedge accounting has been elected.

The fair values of Mirant s price risk management assets and liabilities, net of credit reserves, at December 31, 2006, are included in the following table (in millions):

	Net Price Risk Management Assets Current	Noncurrent	Net Price Risk Management Liabilities Current	Noncurrent	Net Fair Value at December 31, 2006
Electricity	$ 603	$ 99	$ (247)	$ (8)	$ 447
Back-to-Back Agreement(1)			(36)	(389)	(425)
Natural Gas	21	1	(26)	(2)	(6)
Oil	83		(10)	(29)	44
Coal	13		(3)		10
Other, including credit reserves	(5)				(5)
Total	$ 715	$ 100	$ (322)	$ (428)	$ 65

(1) contractual arrangement with Pepco with respect to certain PPAs, including Pepco s long-term PPA with Panda and Ohio Edison (the Back-to-Back Agreement).

The following table represents the net price risk management assets and liabilities by tenor at December 31, 2006 (in millions):

	Back-to-Back Agreement	All Other Agreements
2007	$ (36)	$ 429
2008	(31)	13
2009	(30)	40
2010	(36)	9
Thereafter	(292)	(1)
Net (liabilities) assets	$ (425)	$ 490

The volumetric weighted average maturity, or weighted average tenor, of the price risk management portfolio, excluding the Back-to-Back Agreement, at December 31, 2006, was approximately 11 months. The net notional amount of the price risk management assets and liabilities, excluding the Back-to-Back Agreement, at December 31, 2006, was a net short position of approximately 24 million equivalent MWh.

The fair values of Mirant s price risk management assets and liabilities, net of credit reserves, at December 31, 2005, are included in the following table (in millions):

	Net Price Risk Management Assets Current	Noncurrent	Net Price Risk Management Liabilities Current	Noncurrent	Net Fair Value at December 31, 2005
Electricity	$ 448	$ 61	$ (704)	$ (20)	$ (215)
Back-to-Back Agreement			(26)	(417)	(443)
Natural Gas	113	19	(112)	(20)	
Oil	21	11	(5)		27
Coal	31	24	(2)	(1)	52
Other, including credit reserves	(11)				(11)
Total	$ 602	$ 115	$ (849)	$ (458)	$ (590)

Fair Values

Financial instruments recorded at market or fair value include cash and interest-bearing cash equivalents, derivative financial instruments and financial instruments used for price risk management purposes. The following methods were used by Mirant to estimate the fair value of all financial instruments that are not subject to compromise and 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.

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

The carrying or notional amounts and fair values of Mirant s financial instruments at December 31, 2006 and 2005 are as follows (in millions):

	December 31, 2006 Carrying Amount	Fair Value
Liabilities:		
Notes payable and long- and short-term debt Continuing Operations	$ 3,275	$ 3,338
Other:		
Notes and other receivables Continuing Operations	13	13

	December 31, 2005 Carrying Amount	Fair Value
Liabilities:		
Notes payable and long- and short-term debt Continuing Operations	$ 2,582	$ 2,582
Other:		
Notes and other receivables Continuing Operations	27	27

8. Property, Plant and Equipment, net

Property, plant and equipment, net consisted of the following at December 31, 2006 and 2005 (in millions):

	At December 31, 2006	At December 31, 2005	Depreciable Lives (years)
Production	$ 2,506	$ 2,444	14 to 36
Construction work in progress	195	80	
Other	208	201	2 to 12
Suspended construction projects	8	174	
Less: accumulated depreciation, depletion and amortization and provision for impairment	(705)	(571)	
Total property, plant and equipment, net	$ 2,212	$ 2,328	

Property, plant and equipment, net of $3.5 billion and $3.7 billion has been reclassified to assets held for sale in the Company s consolidated balance sheets at December 31, 2006 and 2005, respectively. See Note 3 for additional information on assets held for sale.

Suspended construction projects decreased in 2006 due to the transfer of Contra Costa unit 8 to PG&E pursuant to a Settlement and Release of Claims Agreement and the impairment loss of $120 million related to Bowline unit 3. See California Settlement in Note 23 for additional information regarding the CC8 assets. See Note 4 for further discussion related to impairments of long-lived assets.

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. Mirant does not depreciate its suspended construction project costs or property, plant and equipment that has been reclassified to assets held for sale. The Company received emissions allowances in the acquisition of the Pepco assets for both SO2 and NOx emissions and the right to future allowances. The acquired allowances related to owned facilities are included in production assets above, and are depreciated over the average life of the related assets.

Mirant evaluates its long-lived assets (property, plant and equipment) and definite-lived intangibles for impairment whenever events or changes in circumstances indicate that the Company may not be able to recover the carrying amount of the asset. An asset impairment charge must be recognized if the sum of the undiscounted expected future cash flows from a long-lived asset or definite-lived intangible 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 the case of assets the Company expects to sell, the impairment charge is based on the estimated sales value less costs to sell. For additional information on impairments see Note 4.

9. Intangible Assets, net

Following is a summary of intangible assets at December 31, 2006 and 2005 (in millions):

		At December 31, 2006		At December 31, 2005	
	Weighted Average Amortization Lives	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Trading rights	26 years	$ 27	$ (3)	$ 27	$ (2)
Development rights	37.5 years	62	(9)	62	(7)
Emissions allowances	32 years	151	(25)	151	(21)
Other intangibles	26.5 years	14	(3)	17	(2)
Total other intangible assets		$ 254	$ (40)	$ 257	$ (32)

Other intangible assets, net of $51 million and $58 million related to assets to be sold have been reclassified to assets held for sale in the Company s consolidated balance sheets at December 31, 2006 and 2005, respectively. See Note 3 for additional information on assets held for sale.

Trading rights represent 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 generation facilities.

Emissions allowances recorded in intangible assets relate to allowances granted for the leasehold baseload units at the Morgantown and Dickerson facilities, as well as the Company s units in California. Allowances granted by the EPA for other owned assets are recorded within property, plant and equipment, net on the consolidated balance sheets.

Substantially all of Mirant s other remaining intangible assets are subject to amortization and are being amortized on a straight-line basis over their estimated useful lives, ranging from 8 to 40 years.

Amortization expense was approximately $8 million for the years ended December 31, 2006, 2005 and 2004. Assuming no future acquisitions, dispositions or impairments of intangible assets, amortization expense is estimated to continue at this level for each of the next five years.

10. Long-Term Debt

Long-term debt at December 31, 2006 and 2005 was as follows (in millions):

	At December 31, 2006	**At December 31, 2005**	**Interest Rate**	**Secured/ Unsecured**
Long-term Debt:				
Mirant Americas Generation:				
Senior notes:				
Due 2011	$ 850	$ 850	8.30%	Unsecured
Due 2021	450	450	8.50%	Unsecured
Due 2031	400	400	9.125%	Unsecured
Unamortized debt premium/discount	(4)	(4)		
Mirant North America:				
Term loan, due 2007 to 2013	693		LIBOR + 1.75%	Secured
Notes, due 2013.	850	850	7.375%	Unsecured
Capital leases, due 2007 to 2015	36	36	7.375% - 8.19%	
Total Mirant Corporation	3,275	2,582		
Less: current portion of long-term debt	(142)	(3)		
Total long-term debt, excluding current portion	$ 3,133	$ 2,579		

Pursuant to the Plan, Mirant s wholly-owned subsidiary, Mirant Americas Generation, reinstated $1.7 billion of senior notes maturing in 2011, 2021 and 2031. During 2006, approximately $1.3 billion and $1.1 billion of long-term debt was reclassified to liabilities held for sale on the Company s consolidated balance sheets at December 31, 2006 and December 31, 2005, respectively. See Note 3 for additional information on liabilities held for sale.

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 an $800 million six-year senior secured revolving credit facility and a $700 million seven-year senior secured term loan. The full amount of the senior secured revolving credit facility is available for cash draws or for the issuance of letters of credit. On January 3, 2006, Mirant North America drew $465 million under its senior secured revolving credit facility. All amounts were repaid during the first quarter of 2006. The senior secured term loan was fully drawn at closing and amortizes in quarterly installments aggregating 0.25% of the original principal of the term loan per quarter for the first 27 quarters, with the remainder payable on the final maturity date in January 2013. 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. As of December 31, 2006, there were approximately $198 million of letters of credit outstanding under the term loan and $6 million outstanding under the revolver. The senior secured credit facilities are obligations of Mirant North America and the respective guarantors and are not recourse to any other Mirant entities.

Mirant North America is required to prepay a portion of the outstanding principal balance of the senior secured term loan once a year, in addition to the regularly scheduled principal payments, based on an EBITDA calculation to determine excess free cash flows, as defined in the loan agreement. At December 31, 2006, the current estimate of the mandatory principal prepayment of the term loan in March 2007 is approximately $131 million. This amount has been reclassified from long-term debt to current portion of long-term debt at December 31, 2006.

The sale of the Zeeland and Bosque natural gas-fired plants is subject to the terms of the Mirant North America senior secured credit facilities, including the mandatory prepayment and/or reinvestment provisions and the requirement to secure credit rating affirmations. Mirant North America has received the required credit rating affirmations.

Senior Notes

In December 2005, Mirant North America issued the Old Notes in an aggregate principal amount of $850 million that bear interest at 7.375% and mature on December 31, 2013. The senior notes were issued in a private placement and were not registered with the SEC. Interest on the notes is payable on each June 30 and December 31, commencing June 30, 2006. The proceeds of the 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. The senior notes are obligations of Mirant North America and the respective guarantors and are not recourse to any other Mirant entities.

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

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. At any time prior to December 31, 2008, Mirant North America may redeem up to

35% of the original principal amount of the notes with the proceeds of certain equity offerings at a redemption price of 107.375% of the principal amount of the notes, 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.

The sale of the Zeeland and Bosque natural gas-fired plants is subject to the terms of the Mirant North America senior notes, including the provisions with respect to a mandatory offer to purchase debt and/or reinvest with the sale proceeds.

At December 31, 2006, the annual scheduled maturities of debt during the next five years and thereafter were as follows (in millions):

2007	$ 142
2008	10
2009	11
2010	11
2011	861
Thereafter	2,240
Total	$ 3,275

Other than for 2007, the annual scheduled maturities above do not include estimates of Mirant North America s required payments of its senior secured term loan based on its EBITDA.

Capital Leases

Long-term debt includes a capital lease by Mirant Chalk Point. At December 31, 2006 and 2005, the current portion of the long-term debt under this capital lease was $3 million and $3 million, respectively. The amount outstanding under the capital lease, which matures in 2015, is $34 million with an 8.19% annual interest rate. This lease is of an 84 MW peaking electric power generation facility. Depreciation expense related to this lease was approximately $2 million for each of the years ended December 31, 2006, 2005 and 2004. The annual principal payments under this lease are approximately $3 million in 2007 through 2010, $4 million in 2011 and $18 million thereafter. The gross amount of assets under the capital lease, recorded in property, plant and equipment, net as of December 31, 2006 and 2005, was $24 million. The related accumulated depreciation was $10 million and $8 million as of December 31, 2006 and 2005, respectively.

Sources of Funds and Capital Structure

The principal sources of liquidity for the Company s future operations and capital expenditures are expected to be: (i) existing cash on hand and cash flows from the operations of the Company s subsidiaries; (ii) borrowings under Mirant North America s $800 million six-year senior secured revolving credit facility; and (iii) $200 million of letters of credit capacity under Mirant North America s $700 million term loan.

The Company and certain of its subsidiaries, including Mirant Americas Generation and Mirant North America, are holding companies and as a result, 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 distributions is restricted under the terms of their debt or other agreements. In particular, a substantial portion of the cash from the Company s United States 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 payments test is not satisfied, the cash of Mirant Mid-Atlantic would not be able to be distributed. Based on the Company s calculation of the fixed charge coverage ratios under the leveraged leases as of December 31, 2006, Mirant Mid-Atlantic meets the required 1.7 to 1.0 ratio for restricted payments, both on a historical and projected basis.

The Plan provided for the organization of Mirant North America as an intermediate holding company that is a subsidiary of Mirant Americas Generation and the parent of its indirect subsidiaries, including Mirant Mid-Atlantic. Pursuant to the confirmed Plan, Mirant North America incurred certain indebtedness and entered into a revolving credit facility for working capital and other purposes secured by the assets of Mirant North America and its subsidiaries (other than Mirant Mid-Atlantic and its subsidiaries). The revolving credit facility includes certain covenants typical in such credit facilities, including restrictions on dividends, distributions and other restricted payments. Further, the revolving credit facility includes financial covenants that will exclude from the calculation of compliance with such covenants the financial results of any subsidiary that is unable to make distributions or dividends at the time of such calculation. Thus, the ability of Mirant Mid-Atlantic to make distributions to Mirant North America under the leveraged lease transaction could have a material impact on the calculation of the financial covenants under the revolving credit facility and other debt of Mirant North America and on its ability to make distributions to Mirant Americas Generation.

11. Investments

For the years ended December 31, 2006 and 2005, the Company completed the sales of investments described below. The related gains are recorded in gain on sale of investments, net in the consolidated statements of operations.

Equity Investment in ICE. In the fourth quarter of 2005, the Company sold a portion of its investment in ICE for $48 million and realized a gain of $44 million. In 2006 the Company sold its remaining investment in ICE for $58 million and realized a gain of $54 million.

New York Mercantile Exchange Seats. In late 1998 and early 1999, the Company acquired two seats on the New York Mercantile Exchange for approximately $1.2 million, which were recorded as an investment in the consolidated balance sheet at December 31, 2005. In the fourth quarter of 2006, the Company sold its investment for $20 million and recognized a gain of $19 million, which is recorded in gain on sales of investments, net on the Company s consolidated statement of operations.

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, 2006 and 2005, amounts related to allowed claims, estimated unresolved claims and professional fees associated with the bankruptcy that are to be settled in cash were $28 million and $1.903 billion, respectively, and these amounts were recorded in claims payable and estimated claims accrual 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. During the year ended December 31, 2006, the Company paid approximately $1.849 billion in cash related to bankruptcy claims. Of this amount approximately $990 million is reflected in cash flows from financing activities from continuing operations and $45 million from discontinued operations and represents the principal amount of debt claims. The remaining $814 million is reflected in cash flows from operating activities and represents other bankruptcy claims and interest. As of December 31, 2006, approximately 21 million 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 23 for further discussion of the Chapter 11 proceedings.

Financial Statements of Subsidiaries in Bankruptcy

Mirant s New York subsidiaries remain in bankruptcy and include the following entities: Mirant Lovett, Mirant Bowline, Mirant NY-Gen, Mirant New York and Hudson Valley Gas Corporation. Consolidated financial statements of Mirant s New York subsidiaries are set forth below:

Mirant New York Subsidiaries
Condensed Consolidated Statements of Operations Data
(in millions)

	Years Ended December 31,		
	2006	2005	2004
Operating revenues	$ 336	$ 433	$ 244
Cost of fuel, electricity and other products	162	361	139
Operating expenses	193	178	214
Operating loss	(19)	(106)	(109)
Other expense, net	16	2	1
Reorganization items, net(1)	(163)	(2)	15
Provision (benefit) for income taxes	2	1	(1)
Cumulative effect of change in accounting principles		2	
Net income (loss)	$ 126	$ (109)	$ (124)

(1) In 2006, reorganization items, net is related to the pre-petition gain on the New York Property Tax Settlement.

F-34

Mirant New York Subsidiaries
Condensed Consolidated Balance Sheets Data
(in millions)

	At December 31, 2006	2005
Assets-affiliate	$ 104	$ 149
Assets-nonaffiliate	223	35
Property, plant and equipment, net	366	502
Total assets	$ 693	$ 686
Liabilities not subject to compromise:		
Liabilities-affiliate	$ 28	$ 36
Liabilities-nonaffiliate	65	177
Liabilities subject to compromise affiliate	62	62
Liabilities subject to compromise nonaffiliate	18	18
Member s equity	520	393
Total liabilities and member s equity	$ 693	$ 686

Mirant New York Subsidiaries
Condensed Consolidated Statements of Cash Flows Data
(in millions)

	Years Ended December 31, 2006	2005	2004
Net cash provided by (used in):			
Operating activities	$ 17	$ (18)	$ (46)
Investing activities	72	(4)	41
Financing activities	9	23	5
Net increase in cash and cash equivalents	98	1	
Cash and cash equivalents, beginning of period	1		
Cash and cash equivalents, end of period	$ 99	$ 1	$

Liabilities Subject to Compromise

The Company s liabilities subject to compromise, which relate to its New York subsidiaries that remain in bankruptcy, are $18 million at December 31, 2006 and 2005.

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, 2006, 2005 and 2004, are comprised of the following (in millions):

	Years Ended December 31,		
	2006	2005	2004
Gain on the implementation of the Plan	$	$ (285)	$
Gain on New York property tax settlement	(163)		
Estimated claims and losses on rejected and amended contracts(1)	2	72	132
Professional fees and administrative expense		226	109
Interest income, net	(2)	(31)	(14)
Total	$ (163)	$ (18)	$ 227

(1) Estimated claims and losses on rejected and amended contracts relate primarily to rejected energy contracts, such as tolling agreements, gas transportation and electric transmission contracts.

Interest Expense

The 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. In the third quarter of 2005, the Company determined that it was probable that contractual interest on liabilities subject to compromise from the Petition Date would be incurred for certain claims expected to be allowed under the Plan. As a result, the Company recorded interest expense of approximately $1.4 billion in 2005 on liabilities subject to compromise. This amount represents interest from the Petition Date through the effective date of the Plan. The interest amount was calculated based on the provisions of the Plan. The $1.4 billion expense amount included approximately $450 million related to Mirant Americas Generation senior notes maturing in 2011, 2021 and 2031, which were reinstated under the confirmed Plan.

13. Income Taxes

Income or loss from continuing operations before income taxes for the periods ended December 31, 2006, 2005 and 2004 amounted to $1.195 billion of pre-tax income, $1.408 billion of pre-tax loss and $1 million of pre-tax loss, respectively.

The provision (benefit) for income taxes from continuing operations is as follows (in millions):

	Years Ended December 31,		
	2006	2005	2004
Current income tax provision (benefit)	$ 2	$ (4)	$ (18)
Deferred income tax provision (benefit)	(580)	(14)	16
Benefit for income taxes	$ (578)	$ (18)	$ (2)

A reconciliation of the Company s federal statutory income tax provision to the effective income tax provision for continuing operations adjusted for restructuring items for the years ended December 31, 2006, 2005 and 2004 is as follows (in millions):

	Years Ended December, 31, 2006	2005	2004
Provision (benefit) for income taxes based on United States federal statutory income tax rate	$ 418	$ (492)	$
State and local income tax (benefit), net of federal income taxes	77	69	(5)
Discontinued Operations	(91)	(27)	(246)
Return to Provision Adjustments:			
Professional fees during bankruptcy	65		
Previously deferred intercompany gain	22		
Foreign reorganization gain	83		
Other	50		
Anticipated effect of 382(1)(5)	297		
Taxes accrued on foreign earnings	16	31	64
Netherlands NOL write-off		164	
Reorganization adjustments		(91)	
Change in deferred tax asset valuation allowance	(1,513)	260	161
Other differences, net	(2)	68	24
Tax benefit	$ (578)	$ (18)	$ (2)

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

	December 31, 2006	2005
Deferred Tax Assets:		
Employee benefits	$ 30	$ 43
Reserves	80	223
Operating and capital loss carryforwards	1,333	1,560
Tax basis in excess of book basis in foreign investments expected to be realized	335	
Property and intangible assets	146	475
Energy marketing and risk management contracts		170
Other	59	282
Subtotal	1,983	2,753
Valuation allowance	(1,115)	(2,628)
Net deferred tax assets	$ 868	$ 125
Deferred Tax Liabilities:		
Energy marketing and risk management contracts	(92)	
Taxes accrued on foreign earnings	(15)	
Other	(40)	(125)
Net deferred tax liabilities	(147)	(125)
Net deferred taxes	$ 721	$

The ultimate utilization of the Company s remaining NOLs will depend on several factors, including the Company s future financial performance and certain tax elections. Specifically, Mirant s utilization of

NOLs will be affected by whether the Company elects NOL treatment under Internal Revenue Code section (§) 382(l)(5) or § 382(l)(6). The Company currently anticipates that the treatment under § 382(l)(5) of the Internal Revenue Code will apply to Mirant going forward. Under that treatment, Mirant would have use of its NOLs as long as there is not a change of ownership (broadly defined as 50 percent change of five percent shareholders) within two years of emergence from bankruptcy. The § 382(l)(5) treatment requires us to reduce the Company s NOLs by $ 1.1 billion due to interest accrued on debt settled with stock for the three years prior to emergence. Under § 382(l)(6), the Company would be subject to an annual limitation on use of NOLs. Mirant will make the § 382(l)(5) or § 382(l)(6) election in its 2006 annual tax return to be filed in 2007. Given the likelihood that Mirant will elect under 382 (l)(5) the Company has adjusted various deferred income tax items including the NOLs.

SFAS No. 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 determination of a valuation allowance requires significant judgment as to the generation of taxable income during future periods for which temporary differences are expected to be deductible. In making this determination, management considers all available positive and negative evidence affecting specific deferred tax assets, including its past and anticipated future performance, the reversal of deferred tax liabilities and the implementation of tax planning strategies.

The company expects to recognize a gain from the sale of its Philippine business in 2007 at the time that transaction is closed and sales proceeds are received. As required by applicable accounting principles, an enterprise that anticipates the realization of a pretax 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. The Company has recognized in 2006 a tax benefit in the amount of $721 million related to the pending sale of its Philippine business in 2007. This benefit has two components: a) $580 million recognized for continuing operations related to the release of the valuation allowance pertaining to deferred assets previously recorded including the estimated value of the NOLs that will be used to offset the anticipated 2007 taxable gain resulting from the sale; and b) $141 million recognized for the Company s discontinued operations related to the value of the additional difference between the book basis and the tax basis in the shares of the entity being sold. Each year, Mirant s net U.S. Federal deferred tax assets have been reduced by a valuation allowance to reflect the amount that was estimated to be recoverable. It is management s judgment based on available evidence that it is more-likely-than-not that deferred tax assets relating to this transaction will be recoverable in 2007. Management has considered all available positive and negative evidence affecting these specific deferred tax assets in making this decision and has determined the valuation allowance related to such deferred tax assets should be released in 2006. In addition, based on the pending sale of the Philippine business, the Company no longer intends to distribute earnings in the form of a dividend prior to the completed sale. As a result, Mirant has recognized an additional net tax benefit of $124 million in discontinued operations related to the reversal of previously accrued foreign withholding taxes.

In the case of the pending sale of the Company s Philippine business, the practical effect of the difference in the recognition standard for the gain on the sale and that for the associated tax attributes is to cause the tax benefits associated with the sale to be taken into account in 2006 (prior to when the gain on the sale is taken into account). As a result, in 2007 when the Company expects to recognize the gain from the sale of the Philippine business, the transaction will be reflected as fully taxable.

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. Future performance relating to the sale of the Philippine assets is the most compelling form of positive evidence considered by management in the determination of the future recoverability of a portion of its net deferred assets. In 2006, the Company recognized a decrease of $1,513 million in its valuation allowance related to its net deferred tax assets. In 2005, the Company recognized an increase of $260 million in its valuation allowance related to its net deferred tax assets.

As of December 31, 2006, the Company has approximately $3.1 billion of U.S. federal NOL carryforwards for financial reporting purposes with expiration dates from 2022 to 2026. Similarly, there is an approximate aggregate amount of $5.2 billion of state NOL carryforwards with various expiration dates (based on the application of apportionment factors and other state tax limitations).

Additionally, the Company has contingent liabilities related to tax uncertainties arising in the ordinary course of business. Mirant periodically assesses its contingent liabilities in connection with these uncertainties based on the latest information available. For those uncertainties where it is probable that a loss has occurred and the loss or range of loss can be reasonably estimated, a liability is recognized in the financial statements. The recognition of contingent losses for tax uncertainties requires management to make significant assumptions about the expected outcomes of certain tax contingencies. On January 1, 2007, the Company will change its method of determining tax contingencies upon adoption of FIN 48. Upon initial adoption, the provisions of FIN 48 will be applied to all tax positions. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized. The Company anticipates that the adoption of FIN 48 will result in a decrease in accrued liabilities and liabilities held for sale that together will be approximately $50 million to $125 million. The decreases in accrued liabilities and liabilities held for sale will result in an increase of retained earnings of the same amount.

14. Employee Benefit Plans

Pension Plans

Mirant offers 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 date for the defined benefit plans is September 30 for each year presented.

As discussed in Note 2, SFAS No. 158 was adopted as of December 31, 2006. SFAS No. 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 in its balance sheets rather than merely disclosing the funded status in the financial statement footnotes. The Company adopted SFAS No. 158 on December 31, 2006, and recognized an increase in other noncurrent liabilities of $21 million related to its underfunded domestic defined benefit pension plans.

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

	Tax-Qualified 2006	2005	Non-Tax Qualified 2006	2005
Change in benefit obligation:				
Benefit obligation, beginning of year	$ 245	$ 202	$ 12	$ 9
Service cost	10	9		
Interest cost	13	11	1	1
Benefits paid	(7)	(6)		
Actuarial (gain) loss	(17)	29	(4)	2
Benefit obligation, end of year	$ 244	$ 245	$ 9	$ 12
Change in plan assets:				
Fair value of plan assets, beginning of year	$ 109	$ 89	$	$
Return on plan assets	11	11		
Employer contributions	38	15		
Benefits paid	(7)	(6)		
Fair value of plan assets, end of year	$ 151	$ 109	$	$
Funded Status:				
Funded status at measurement date	$ (93)	$ (136)	$ (9)	$ (12)

The accumulated benefit obligation exceeded the fair value of plan assets at year-end 2006 for all pension plans. The total accumulated benefit obligation as of September 30, 2006, was $210 million.

The rates assumed in the actuarial calculations for measuring year-end pension obligations as of their respective measurement dates are listed in the table below. The discount rate is based on the Moody s Aa Corporate Bond Rate as of September 30.

	2006	2005
Discount rate	5.66 %	5.36 %
Rate of compensation increases	3.70 %	3.82 %

Amounts recognized in the consolidated balance sheet at December 31, 2006, under SFAS No. 158 (in millions):

	Tax-Qualified	Non-Tax Qualified
Noncurrent liabilities	$ (93)	$ (9)
Total amount recognized at measurement date	$ (93)	$ (9)
Total amount recognized on consolidated balance sheet	$ (93)	$ (9)

F-40

Amounts recognized in the consolidated balance sheet at December 31, 2005, under prior accounting rules are as follows (in millions):

	Tax-Qualified	Non-Tax Qualified
Funded status at measurement date	$ (136)	$ (12)
Unrecognized prior service cost	3	2
Unrecognized net actuarial loss	37	6
Net prepaid/(accrued) pension benefit cost	(96)	(4)
Intangible asset		(2)
Additional liability recognized in accumulated other comprehensive loss		(3)
Total liability recognized	(96)	(9)
Fourth quarter funding	3	
Total liability recognized on consolidated balance sheet	$ (93)	$ (9)

Amounts recognized in accumulated other comprehensive income at December 31, 2006, under SFAS No. 158 (in millions):

	Tax-Qualified	Non-Tax Qualified
Net loss	$ (17)	$ (1)
Prior service credit	(3)	(3)
Total amounts included in accumulated other cumulative loss	$ (20)	$ (4)

Expected amortization payments. The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $0.2 and $0.5 million, respectively.

The components of the net periodic cost of Mirant s pension plans for the years ended December 31, 2006, 2005 and 2004 are shown below (in millions):

	Years Ended December 31, 2006	2005	2004
Service cost	$ 10	$ 9	$ 10
Interest cost	14	12	11
Expected return of plan assets	(10)	(8)	(7)
Net amortization(1)	2		
Net periodic pension cost	$ 16	$ 13	$ 14

(1) Amount includes unrecognized transition obligation or asset, prior service cost and actuarial gains or losses.

The rates assumed in the actuarial calculations for measuring pension cost each year were as follows:

	2006	2005
Discount rate	5.36 %	5.73 %
Rate of compensation increase	3.82 %	3.00 %
Expected return on plan assets	8.50 %	8.50 %

In determining the long-term rate of return for plan assets, historical markets and current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are

F-41

determined and consideration of diversification and portfolio rebalancing is given. Peer data and historical returns are reviewed to check for reasonableness and appropriateness.

The following table shows the target allocation and percentage of fair value of plan assets by asset category for Mirant s qualified pension plans for 2006 and 2005:

	2006		2005	
	Target Allocation	Percent of Fair Value of Plan Assets	Target Allocation	Percent of Fair Value of Plan Assets
U.S. Stocks	55 %	56 %	55 %	54 %
Non-U.S. Stocks	15	14	15	16
Fixed income	30	30	30	30
Total	100 %	100 %	100 %	100 %

For the qualified pension plans, Mirant uses a mix of equities and fixed income investments in an attempt to maximize the long-term return of plan assets for a prudent level of risk. 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 the Invesco International Equity Fund that is benchmarked against the EAFE Index. Fixed income investments include a passive bond market index fund which seeks to replicate the Lehman Brothers Aggregate Bond Index. Investment risk is monitored on an ongoing basis through quarterly portfolio reviews and annual pension liability measurements.

During 2007, Mirant expects to contribute approximately $22 million to the domestic qualified pension plans and approximately $0.2 million to the domestic non-tax-qualified pension plans. Additionally, Mirant expects the following benefits to be paid from the pension plans (in millions):

Projected Benefit Payments to Plan Participants	Tax-Qualified	Non-Tax Qualified
2007	$ 6.9	$ 0.2
2008	7.5	0.3
2009	7.9	0.3
2010	8.5	0.3
2011	9.3	0.3
2012 through 2016	68.2	2.0

Other Postretirement Benefits

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 date for these domestic other postretirement benefit plans is September 30 for each year presented.

As discussed in Note 2, SFAS No. 158 was adopted as of December 31, 2006. SFAS No. 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 in its balance sheets rather than merely disclosing the funded status in the financial statement footnotes. The Company adopted SFAS No. 158 on December 31, 2006, and recognized a decrease in other noncurrent liabilities of $5 million related to its other postretirement benefit plans.

During the fourth quarter of 2006, Mirant amended the postretirement benefit plan covering nonunion employees to eliminate all employer provided subsidies through a gradual phase-out by 2011. Since this action occurred after the measurement date, it is not reflected in the figures shown for year-end 2006, but will be recognized during the first quarter of fiscal 2007 as a plan curtailment. As a result, Mirant expects to recognize a reduction in other postretirement liabilities of approximately $32 million.

The following table shows the obligations and funded status for other postretirement benefit plans of Mirant (in millions):

	Years Ended December 31, 2006	2005
Change in benefit obligation:		
Benefit obligation, beginning of year	$ 127	$ 135
Service cost	4	4
Interest cost	7	8
Amendments	(17)	(33)
Actuarial (gain) loss	(11)	16
Benefits paid	(3)	(3)
Benefit obligation, end of year	$ 107	$ 127
Change in plan assets:		
Employer contributions	$ 3	$ 3
Benefits paid	(3)	(3)
Fair value of plan assets, end of year	$	$
Funded Status:		
Funded status at measurement date	$ (107)	$ (127)

Weighted average rates assumed in the actuarial calculations for other postretirement benefit obligations as of their respective measurement dates were as follows:

	2006	2005
Discount rate	5.66 %	5.36 %
Rate of compensation increases	3.00 %	3.00 %
Assumed medical inflation for next year		
Before age 65	9.00 %	10.00 %
After age 65	11.00 %	12.50 %
Assumed ultimate medical inflation rate	5.00 %	5.00 %
Year in which ultimate rate is reached	2011	2011

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 at December 31, 2006, by $0.2 million.

Amounts recognized in the consolidated balance sheet at December 31, 2006, under SFAS No. 158 are as follows (in millions):

	December 31, 2006
Current liabilities	$ (4)
Noncurrent liabilities	(103)
Total amount recognized at measurement date	(107)
Employer contributions after measurement date	1
Total amount recognized at year-end	$ (106)

Amounts recognized in the consolidated balance sheet at December 31, 2005, under prior accounting rules are as follows (in millions):

	December 31, 2005
Funded status at measurement date	$ (127)
Unrecognized net actuarial loss	57
Unrecognized prior service credit	(35)
Employer contributions after measurement date	1
Net prepaid/(accrued) postretirement benefit cost	$ (104)

Amounts recognized in accumulated other comprehensive income at December 31, 2006, under SFAS No. 158 are as follows (in millions):

	December 31, 2006
Net loss	$ (43)
Prior service cost	48
Total amounts included in accumulated other cumulative income	$ 5

Expected amortization payments. The estimated net loss and prior service credit 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 $3 and $(7) million, respectively. These expected amortizations are based on the plans as they existed at the measurement date and, as such, do not reflect the effects of the gradual phase-out of retiree welfare subsidies for nonunion employees beginning in 2007.

The components of the net expense for Mirant s postretirement benefit plans during the years ended December 31, are shown below (in millions):

	Years Ended December 31, 2006	2005	2004
Service cost	$ 4	$ 4	$ 4
Interest cost	7	8	7
Net amortization	(1)	2	1
Net postretirement benefit expense	$ 10	$ 14	$ 12

The weighted average rates assumed in the actuarial calculations for Mirant s postretirement benefit costs during each year are shown below:

	December 31, 2006	2005
Discount rate	5.36 %	5.73 %
Rate of compensation increases	3.00 %	3.00 %
Assumed medical inflation for current year		
Before age 65	10.00 %	11.00 %
After age 65	12.50 %	14.00 %
Assumed ultimate medical inflation rate	5.00 %	5.00 %
Year in which ultimate rate is reached	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 postretirement benefit cost in 2006 by approximately $0.3 million.

In 2007, Mirant expects to contribute approximately $4 million to pay other postretirement benefits for retired domestic employees. Additionally, Mirant expects the following net benefits to be paid from the postretirement benefit plans (in millions):

Projected Benefit Payments to Plan Participants	Before Medicare Subsidy	Medicare Subsidy
2007	$ 4.0	$ 0.0
2008	4.7	0.0
2009	5.2	0.1
2010	5.7	0.1
2011	6.0	0.1
2012 through 2016	37.4	1.0

Employee Savings 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 (match 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 those employees not accruing a benefit under the defined benefit pension plan. Expenses recognized for the matching and profit sharing contributions were as follows (in millions):

	Matching	Profit Sharing Arrangement
2006	$ 5	$ 3
2005	5	4
2004	5	2

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 had both service condition and performance condition forms of stock-based compensation at December 31, 2006.

In the first quarter of 2006, the Company made grants of stock options, restricted stock, and restricted stock units totaling 3.3 million. In addition, the Company granted an additional 300,000 awards related to the hiring of new employees during 2006. These grants vest based on a required length of service with the Company.

On October 5, 2006, the Compensation Committee of the Board of Directors of Mirant Corporation 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 consist of options to acquire the Company s common stock and restricted stock units. These grants are considered performance condition awards, as the payout under the November 13, 2006, awards is based on achieving certain target amounts related to the sales of the Company s Philippines and Caribbean businesses and the six gas-fired plants in the United States. The achievement of the target amounts was deemed probable on the date of grant and at December 31, 2006.

As discussed in Note 2, SFAS No. 123R was adopted by the Company during the first quarter of 2006, using the modified prospective transition method. For the year ended December 31, 2006, the Company recognized approximately $16 million and $1 million, respectively, of expense related to service condition and performance condition stock-based compensation. These amounts are included in operations and maintenance expense in the consolidated statements of operations.

As of December 31, 2006, there was approximately $25 million and $11 million of total unrecognized compensation cost related to non-vested share-based compensation granted through service condition and performance condition awards, respectively. That cost is expected to be recognized on a straight-line basis over a weighted-average period of 1.2 years.

Prior to the Company s adoption of SFAS No.123R, Mirant accounted for stock-based employee compensation plans under the intrinsic-value method of accounting for recognition, but disclosed fair value pro forma information. Under that method, compensation expense for employee stock options is measured on the date of grant only if the current market price of the underlying stock exceeds the exercise price. The following table illustrates the effect on net income for the years ended December 31, 2005 and 2004, if the fair-value-based method had been applied to all outstanding and unvested stock-based awards (in millions):

	Years Ended December 31,	
	2005	**2004**
Net loss, as reported	$ (1,307)	$ (476)
Deduct: Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of related tax effects	(3)	(12)
Pro forma net loss	$ (1,310)	$ (488)

Pursuant to the Plan, all share-based payment awards issued prior to the Company s emergence from bankruptcy were cancelled. As a result, the presentation of information above for the periods ending December 31, 2005 and 2004, is not comparable to the information that follows for the period ending December 31, 2006, because the instruments in existence at December 31, 2005 and 2004, do not exist at December 31, 2006. Additionally, the Company s pre-bankruptcy capital structure differed significantly from the Company s post-emergence capital structure, further degrading comparability between the pre-emergence and post-emergence periods.

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. Due to 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 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 No. 107. Due to the lack of exercise history for the Company, the simplified method for estimating expected term has been used in accordance with SAB No. 107, 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:

	Range	**Weighted Average**
Expected volatility	21 - 37%	31.6%
Expected dividends	0%	0%
Expected term		
Service condition awards	5.2 - 6 years	5.9 years
Performance condition awards	3 years	3 years
Risk-free rate	4.3 - 5.1%	4.5%

Service Condition Awards

During 2006, Mirant made awards of approximately 3 million nonqualified stock options. These options were granted with a 10-year term. Approximately 1.1 million options vest in three equal installments on each of the first, second and third anniversaries of the grant date. Approximately 41,000 options vest one year from the grant date. The remaining 1.8 million options vest 25% six months from the grant date, and 25% on each of the first, second and third anniversaries of the grant date. 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. Approximately 525,000 options vested during the year. Of the total options that vested during the year ended December 31, 2006, approximately 87,000 became exercisable as a result of the termination of certain employees.

The weighted average grant-date fair value of stock options granted during the year ended December 31, 2006, was $10.42. A summary of option activity under the Omnibus Incentive Plan as of December 31, 2006, and changes during the year then ended 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 beginning of the year				
Changes during the year to date:				
Granted	2,987,936	$ 24.89		
Exercised or converted	(23,287)	$ 25.05		
Forfeited	(162,930)	$ 24.96		
Expired				
Outstanding at the end of the year	2,801,719	$ 24.89	9.2	$ 18,720
Exercisable or convertible at the end of the year	501,669	$ 24.83	9.1	$ 3,379

On November 13, 2006, Mirant made awards of approximately 830,000 nonqualified stock options to five members of executive management. These options were granted with a 3-year term and cliff vest in approximately 18 months on June 30, 2008, provided that the Company achieves the performance target amounts by December 31, 2007. 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. The weighted average grant date fair value of performance condition stock options granted during the year ended December 31, 2006, was $6.08. A summary of option activity for performance condition awards under the Omnibus Incentive Plan as of December 31, 2006, and changes during the year ended is presented below: