MIRANT CORP
Form 10-K
March 14, 2006

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, 2005
	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:

Common Stock, par value $0.01 per share

Series A Warrants

Series B Warrants

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. x

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. Large Accelerated Filer x 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 $206,679,075 on June 30, 2005 (based on $0.51 per share, the closing price in the daily composite list for transactions on the Pink Sheets Electronic Quotation Service for that day). As of March 3, 2006, there were 300,000,000 shares of the registrant s Common Stock, $0.01 par value per share outstanding.

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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, you can identify forward-looking statements by terminology such as may, will, should, expect, plan, anticipate, estimate, predict, potential or continue or the negative of these terms or other comparable terminology.

Forward-looking statements are only predictions. Actual events or results may differ materially from any forward-looking statement as a result of various factors, which include:

- legislative and regulatory initiatives regarding deregulation, regulation or restructuring of the electric utility industry; 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;

- our pursuit of potential business strategies, including the disposition or utilization of assets;

- changes in market conditions, including developments in energy and commodity supply, demand, volume and pricing, 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;

- 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 fuel supply and delivery for our facilities;

- curtailment of operations due to transmission constraints;

- environmental regulations that restrict our ability to operate our business;

- war, terrorist activities or the occurrence of a catastrophic loss;

- 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;

- 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 independent system operators (ISOs) or regional transmission organizations (RTOs) that result in a failure to compensate our generation units adequately for all of their costs;

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- 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 on terms and prices acceptable to us;

- legislative and regulatory initiatives and changes in the application of laws and regulations by national and local governments in foreign countries where we have operations;

- political factors that affect our international operations, 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 and our inability to access that cash flow to enable us to make debt service and other payments;

- 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 Mid-Atlantic, LLC (Mirant Mid-Atlantic) contained in its leveraged lease financing agreements;

- 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;

- our ability to negotiate favorable terms from suppliers, counterparties and others and to retain customers because we were previously subject to bankruptcy protection; and

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

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

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.

PART I

Item 1. *Business*

Overview

We are an international energy company whose revenues are primarily generated through the production of electricity in the United States, the Philippines and the Caribbean. As of December 31, 2005, we owned or leased approximately 17,500 megawatts (MW) of electric generating capacity.

Mirant Corporation was originally incorporated in Delaware on April 20, 1993. In conjunction with our emergence from Chapter 11 of Title 11 of the United States Bankruptcy Code (as amended, the Bankruptcy Code), our corporate structure changed. As a result, on January 3, 2006, substantially all of the assets of the old Mirant were transferred to a new Delaware corporation which was then renamed Mirant Corporation (New Mirant) and the former company was transferred to a trust. New Mirant serves as the corporate parent of our business enterprise and pursuant to the Plan of Reorganization (the Plan) has no successor liability for any unassumed obligations of the former company.

We manage our business through three principal operating segments: United States, Philippines and Caribbean. Our United States segment consists of the ownership, long-term lease and operation of power generation facilities and energy trading and marketing operations. The Philippine segment includes ownership, long-term lease or similar interests in power generating facilities. The Caribbean segment includes power generation businesses in Curacao and Trinidad and Tobago, and integrated utilities in the Bahamas and Jamaica. The table below summarizes selected financial information for the year ended December 31, 2005, about our business segments (dollars in millions):

	Revenues	%	Gross Margin	%	Operating Income	%	Total Assets
Business Segment:							
United States	$ 2,963	71 %	$ 971	55 %	$ 46	11 %	$ 8,925
Philippines	491	12	464	27	275	66	2,951
Caribbean	730	17	319	18	93	22	1,224
Corporate and Eliminations					4	1	(188)
Total	$ 4,184	100 %	$ 1,754	100 %	$ 418	100 %	$ 12,912

The annual, quarterly and current reports, and any amendments to those reports, that we file with or furnish to the U.S. Securities and Exchange Commission (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. Information contained in our website is not incorporated into this Form 10-K.

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 after January 3, 2006.

Reorganization under Chapter 11 of the Bankruptcy Code

On July 14, 2003 (the Petition Date), and various dates thereafter, Mirant and 83 of its direct and indirect subsidiaries in the United States (collectively, the Mirant Debtors) filed with the United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division (the Bankruptcy Court) voluntary petitions for relief under the Bankruptcy Code, commencing the case *In re Mirant Corporation et al*., Case No. 03-46590 (DML).

Additionally, on the Petition Date, certain of our Canadian subsidiaries, Mirant Canada Energy Marketing, Ltd. and Mirant Canada Marketing Investments, Inc. (together, the Mirant Canadian Subsidiaries), filed an application for creditor protection under the Companies Creditors Arrangement Act in Canada, which, like Chapter 11, allows for reorganization under the protection of the court system. The Mirant Canadian Subsidiaries emerged from creditor protection on May 21, 2004.

Our businesses in the Philippines and the Caribbean were not included in the court-supervised reorganizations.

During the pendency of the Chapter 11 proceedings, the Mirant Debtors operated their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code, the Federal Rules of Bankruptcy Procedure and applicable orders, as well as other applicable laws and rules. In general, each of the Mirant Debtors, as a debtor-in-possession, was authorized under the Bankruptcy Code to continue to operate as an ongoing business, but not to engage in transactions outside the ordinary course of business without the prior approval of the Bankruptcy Court.

On December 9, 2005, the Bankruptcy Court entered an order confirming our Plan, which became effective on January 3, 2006. The Plan set forth the structure of the Mirant Debtors at emergence and outlined how the claims of creditors and stockholders were to be treated. The implementation of the Plan resulted in, among other things, a new capital structure, the discharge of certain indebtedness, the satisfaction or disposition of various types of claims against us, the assumption or rejection of certain contracts and the establishment of a new Board of Directors.

On January 3, 2006, substantially all of the assets of the old Mirant were transferred to New Mirant, which, pursuant to the Plan, has no successor liability for any unassumed obligations of the old Mirant. On January 31, 2006, the trading and marketing business of Mirant Americas Energy Marketing, L.P. (Mirant Americas Energy Marketing), Mirant Americas Development, Inc., Mirant Americas Production Company, Mirant Americas Energy Capital, LLC, Mirant Americas Energy Capital Assets, LLC, Mirant Americas Development Capital, LLC, Mirant Americas Retail Energy Marketing, L.P., and Mirant Americas Gas Marketing, LLC, (collectively, the Trading Debtors) was transferred to Mirant Energy Trading, LLC (Mirant Energy Trading), which, pursuant to the Plan, has no successor liability for any unassumed obligations of the Trading Debtors. After these transfers took place, old Mirant and the Trading Debtors were transferred to a trust created under the Plan.

In connection with the implementation of the Plan, MC Asset Recovery, LLC (MC Asset Recovery) was formed as our wholly-owned subsidiary on December 30, 2005, to prosecute, settle or liquidate certain avoidance actions filed by Mirant during the Chapter 11 proceedings for the benefit of claimants in the bankruptcy proceedings. For further discussion of such actions and MC Asset Recovery, see Note 15 to our consolidated financial statements contained elsewhere in this report.

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 Public Utility Regulatory Policies Act of 1978 (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. Independent system operators (ISOs) and regional transmission organizations (RTOs) were created to administer the new markets and maintain system reliability. Beginning in the fall of 2001, however, in response to extreme price volatility and energy 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 such plants could be constructed more quickly and were less expensive to permit and build than nuclear facilities or plants fired by other fossil fuels. 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 prices of natural gas during 2005. These high natural gas prices have significantly affected electricity prices in markets where gas fired units generally set the price. Some companies are constructing or attempting to obtain permits to construct additional liquefied natural gas receiving facilities which would increase the non-domestic supply of natural gas to the United States and could help to mitigate natural gas prices.

Coal fired generation and nuclear generation account for approximately 50% and 20%, respectively, of the electricity produced in the United States. Current high electricity prices as a result of high natural gas prices have led to renewed interest in new coal fired or nuclear plants. Some regulated utilities are proposing to construct clean coal units or new nuclear plants, in some cases with governmental subsidies or under legislative mandate. These utilities often are able to recover fixed costs through regulated retail rates, including, in many circumstances, the costs of environmental improvements to existing coal facilities, allowing them to build, buy and upgrade without relying on market prices to recover their investments as we must do.

A number of factors combined to create excess generating capacity in certain U.S. markets, including the 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. Although electricity supply and demand spreads have begun to tighten, we do not expect our primary markets to reach target reserve margins, approximately 15% of excess capacity over peak demand, until 2008 to 2010. However, given the time necessary to permit and construct new power plants, we think that certain markets in the United States need to begin now the process of adding generating capacity to meet growing demand. Many ISOs are considering 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.

As a result of recent events, many regulated utilities are seeking to acquire distressed assets or build new generation, 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

Historically, we managed our business as two operating segments: North America and International. In the fourth quarter of 2005, we changed our management structure significantly. As a result, we now manage the following three operating segments: United States, Philippines and Caribbean. Our reportable segments are strategic businesses that are geographically separated and managed independently. For selected financial information about our business segments and information about geographic areas, see

Note 21 to our consolidated financial statements contained elsewhere in this report. See Item 2. Properties for a complete list of our assets.

United States

Overview

In our United States segment, 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 in the United States are ISOs, utilities, municipal systems, aggregators, electric cooperative utilities, producers, generators, marketers and large industrial customers. In the United States, we serve four primary geographic areas: (i) the Mid-Atlantic Region, (ii) the Northeast Region, (iii) the Mid-Continent Region and (iv) the West Region, including Texas.

Ownership and Operations of Electricity Generation Assets

As of December 31, 2005, we owned or leased generation facilities in the United States with an aggregate generation capacity of over 14,000 MW, including 77 MW that were held for sale as of that date. Our domestic 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 included approximately 25% baseload units, 49% intermediate units and 26% peaking units. Mirant Americas Generation, LLC (Mirant Americas Generation), our wholly-owned subsidiary, owns or controls approximately 85% of our U.S. generating capacity.

Commercial Operations

Our commercial operations consist primarily of procuring fuel, dispatching electricity, hedging the production and sale of electricity by our generating facilities, and providing logistical support for the operation of our facilities (by, for example, procuring transportation for coal). We often sell the electricity we produce into the wholesale market at the prices in effect at the time we produce it (spot prices). Those prices are volatile, however, and in order to reduce the risk of that volatility we often enter into hedges forward sales of electricity into the wholesale market and purchases of enough fuel and emissions allowances to allow us to produce and sell the electricity for different periods of time. We procure these hedges in over-the-counter transactions or exchanges where electricity, fuel and emissions allowances are broadly traded, or through specific transactions with a seller, 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 trading), 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, in support of our asset trading, and to take advantage of opportunities that we may see 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 value-at-risk in our proprietary trading activities.

Our commercial operations were conducted historically through Mirant Americas Energy Marketing. As of February 1, 2006, the energy marketing operations of Mirant Americas Energy Marketing are being performed by Mirant Energy Trading. Pursuant to the Plan, we contributed our interest in the trading and marketing operations conducted by Mirant Americas Energy Marketing to Mirant Energy Trading, a subsidiary of Mirant North America, LLC (Mirant North America). Mirant Americas Energy Marketing and its remaining assets and liabilities were then transferred to a trust on January 31, 2006.

Mirant Energy Trading has contracted with our subsidiaries that own generation facilities to procure fuel, dispatch facilities and sell the electricity generated in the wholesale market. Mirant Energy Trading uses dispatch models to make daily decisions regarding the quantity and the price of the power our facilities will generate and sell into the markets. In markets governed by ISOs and RTOs, Mirant Energy Trading bids the energy from our generation facilities into the day-ahead energy market and sells ancillary services through the ISO markets. Mirant Energy Trading works 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. In non-ISO markets, Mirant Energy Trading conducts business through bilateral transactions pursuant to which Mirant Energy Trading provides dispatch schedules to the generation facilities.

We currently economically hedge a substantial portion of our Mid-Atlantic coal fired baseload generation (generation that is dispatched most of the time) and our New England oil fired generation through over-the-counter transactions. However, we generally do not hedge most of our cycling and peaking units (generating facilities that are not dispatched as frequently) due to the limited value we can extract in the marketplace and the high cost of collateral typically required to support these contracts. As of March 3, 2006, we have economically hedged approximately 90%, 60%, 30%, and 30% of our expected Mid-Atlantic coal fired generation for the remainder of 2006, 2007, 2008 and 2009, respectively, and purchased approximately 100%, 80%, 30% and 30% of the expected Mid-Atlantic coal requirements for such periods. Included in such amounts are financial swap transactions entered into by Mirant Mid-Atlantic with a counterparty in January 2006 pursuant to which Mirant Mid-Atlantic economically hedged approximately 80%, 50%, and 50% of its expected on-peak coal fired baseload generation for 2007, 2008 and 2009, respectively. The financial swap transactions are senior unsecured obligations of Mirant Mid-Atlantic and do not require us to post cash collateral either in the form of initial margin or to secure exposure due to changes in power prices. In addition, as of March 3, 2006, we have economically hedged approximately 50% of our expected oil fired generation in New England for the remainder of 2006 and procured approximately 50% of the corresponding expected oil requirements.

While over-the-counter 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 over-the-counter market. Typically, we are able to sell these products at a higher premium than standard products. For certain generation facilities, we have sought to enter into longer-term transactions to provide certainty of cash flows over an extended period. These transactions are typically tolling transactions whereby we receive a fixed capacity payment and, in return, grant an exclusive right for the counterparty to procure the fuel for the generation facility and take title to the power generated. Additionally, we have facilities in our United States business unit operating under long-term contracted capacity and reliability must run (RMR) contracts. At December 31, 2005, our contracted capacity pursuant to these agreements was approximately 3,840 MW with terms expiring through April 2014.

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 is typically purchased under short-term contracts usually linked to a transparent oil index price. For our gas fired units, fuel is typically purchased under short-term contracts with a variety of suppliers on a day-ahead or monthly basis.

Our coal supply primarily comes from both the Central Appalachian and Northern Appalachian coal regions. All of our coal is delivered by rail. We monitor coal supply and delivery logistics carefully, and despite occasional interruptions of scheduled deliveries 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 approximately 5,256 MW: Chalk Point, Morgantown, Dickerson and Potomac River. Our Mid-Atlantic region had a combined 2005 capacity factor of 39%. Our Mid-Atlantic facilities are located in Maryland and Virginia and were acquired from Potomac Electric Power Company (PEPCO) in December 2000. The Chalk Point facility is the largest 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, and 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, 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 Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) market. For a discussion of the PJM market, see Regulatory Environment United States below. In connection with the acquisition of the Mid-Atlantic facilities from PEPCO in 2000, we, through Mirant Americas Energy Marketing, agreed to supply PEPCO its full load requirement in the District of Columbia under a transition power agreement (TPA), which expired in January 2005 (the DC TPA). There was a similar TPA in place to supply PEPCO s load in Maryland, which expired in June 2004 (the Maryland TPA). We also have participated in standard offer service auctions in Maryland and Washington, D.C. Power sales, made either directly through these functions or indirectly through subsequent market transactions that are a result of the auction process, serve as economic hedges for the Mid-Atlantic assets.

In connection with our acquisition of the Mid-Atlantic facilities from PEPCO in 2000, we agreed to purchase from PEPCO all power it received under long-term power purchase agreements (PPAs) with Ohio Edison Company (Ohio Edison), which expired in 2005, and Panda-Brandywine, L.P. (Panda), which expires in 2021. We and PEPCO entered into a contractual arrangement (Back-to-Back Agreement) with respect to PEPCO s agreements with Panda and Ohio Edison under which (1) PEPCO agreed to resell to us all capacity, energy, ancillary services and other benefits to which it is entitled under those agreements and (2) we agreed to pay PEPCO each month all amounts due from PEPCO to Panda or Ohio Edison for the immediately preceding month associated with such capacity, energy, ancillary services and other benefits. Under the Back-to-Back Agreement, we are obligated to purchase power from PEPCO at prices that are typically higher than existing market prices for power in the PJM market.

We are currently in litigation with PEPCO related to the Back-to-Back Agreement. See Item 3 Legal Proceedings for a further discussion.

On August 24, 2005, power production at all five units of the Potomac River generating facility was temporarily halted in response to a directive from the Virginia Department of Environmental Quality (Virginia DEQ). The decision to temporarily shut down the facility arose from findings of a study commissioned under an agreement with the Virginia DEQ to assess the air quality in the area immediately surrounding the facility. The Virginia DEQ s directive was based on results from the study s computer modeling showing that air emissions from the facility have the potential to contribute to localized, modeled exceedances of the health-based national ambient air quality standards (NAAQS) under certain unusual conditions. On August 25, 2005, the District of Columbia Public Service Commission filed an emergency petition and complaint with the Federal Energy Regulatory Commission (FERC) and the Department of Energy (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 exists with respect to a shortage of electric energy, the DOE ordered Mirant Potomac River, LLC (Mirant Potomac River) to generate electricity at the Potomac River generation 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. The DOE required Mirant Potomac River to submit a plan, on or before December 30, 2005, that met this requirement and did not significantly contribute to NAAQS exceedances. The DOE advised that it would consider Mirant Potomac River s plan in consultation with the Environmental Protection Agency (EPA). 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 the rehearing requests further. 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 immediate operation of one baseload unit and two cycling units, making it possible to bring the entire plant into service within approximately 28 hours. We are selling the output of the facility into PJM. The DOE s order expires after September 30, 2006, but we expect we 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 addresses NAAQS issues. The EPA also asserts 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 Federal Clean Air Act (Clean Air Act) compliance status of the Potomac River facility. The facility will not resume normal operations until it can satisfy the requirements of the Virginia DEQ and the EPA with respect to NAAQS, unless, for reliability purposes, it is required to return to operation by a governmental agency having jurisdiction to order its operation. On January 9, 2006, the FERC issued an order directing PJM and PEPCO to file a long-term plan to maintain adequate reliability in the Washington D.C. area and surrounding region and a plan to provide adequate reliability pending implementation of this long-term plan. On February 8, 2006, PJM and PEPCO filed their proposed reliability plans. We are working with the relevant state and federal agencies with the goal of restoring all five units of the facility to normal operation in 2007.

Northeast Region

We own generating facilities in the Northeast region consisting of approximately 3,063 MW of capacity. Our Northeast region had a combined 2005 capacity factor of 34%.The Northeast region is comprised of the New York and New England sub-regions. 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 Utilities, Inc. (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 approximately 1,672 MW of capacity. The Bowline facility is a 1,125 MW dual-fueled (natural gas and oil) facility comprised of one intermediate/peaking unit and one intermediate unit. 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 136 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 have an operational interest in the Grahamsville facility, which has a hydroelectric baseload unit. Our operational interest in the Grahamsville facility was pursuant to a sublease between Orange and Rockland and Mirant NY-Gen, LLC (Mirant NY-Gen), which expired on December 30, 2005. We have executed an interim agreement to extend this arrangement, which will be in effect until the earlier of December 31, 2006, or the end of the month following the month in which we receive regulatory approvals from the FERC and the New York Public Service Commission to transfer the facility to Orange and Rockland, which will transfer the facility to the City of New York. We received approval of the transfer from the FERC on February 27, 2006. A proposed expansion at the Bowline facility to add a natural gas and distillate oil fired unit with a total of 750 MW of generation capacity is currently suspended and we are attempting to extend permits such that we have the option to complete the project. Our New York plants operate in a market operated by the Independent System Operator of New York (NYISO). For a discussion of the NYISO, see Regulatory Environment United States below.

Our current plan is to retire one unit of the Mirant Lovett, LLC (Mirant Lovett) facility in 2007 and the remaining two units in 2008. However, we are exploring ways in which to avoid retiring the facility. In order for the facility to remain viable, we need to accomplish three primary tasks. First, we need agreements with the local taxing authorities to reduce property taxes. Although conditions remain to be met before the agreements are final, all of the taxing authorities have agreed in principle to refunds for past disputed taxes and substantial reductions in property taxes through 2012. Second, we need to reach agreement with the State of New York on amendments to a consent decree entered into on June 11, 2003, to resolve issues related to the new source review (NSR) regulations promulgated under the Clean Air Act (the 2003 Consent Decree), which amendments would address the installation of environmental equipment. Third, as current market conditions do not allow Mirant Lovett to recover the necessary returns to fund the installation of environmental controls required under the 2003 Consent Decree, we will need an agreement with a third party assuring us of enough revenue to justify required capital expenditures. It is our view that the Lovett facility is necessary to the provision of reliable electricity to New York City and other areas within the NYISO.

In May of 2005, a sinkhole was discovered in the dam of our Swinging Bridge facility. Mirant NY-Gen is currently discussing with the FERC appropriate remediation for this sinkhole. We conducted a flood study to determine downstream consequences if the maximum capacity of the reservoirs were exceeded at our New York Swinging Bridge, Rio and Mongaup generation facilities, which may require that Mirant NY-Gen be requested by the FERC to remediate these dams as well. Mirant NY-Gen has initiated discussions with the FERC for surrendering its permits to operate all the hydro electric facilities at Swinging Bridge, Rio and Mongaup, and expects to begin that formal process soon. It is not possible at this point to determine the cost of remediating the dam and surrendering the permits, but such costs may be substantial.

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 approximately 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 capable of producing 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 8.8 MW) in the 614 MW Wyman Unit 4 located on Cousin s Island, Yarmouth, Maine. It 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 New England Power Pool (NEPOOL) bilateral markets and into the markets administered by the Independent System Operator New England (ISO-NE) through Mirant Energy Trading. For a discussion of the NEPOOL and the ISO-NE, see Regulatory Environment United States below. We had made a determination that market fundamentals in NEPOOL did not permit us to operate the Kendall facility on an economical basis as a merchant facility. We therefore 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 a settlement agreement with NSTAR Electric and Gas Corporation (NSTAR) and ISO-NE and filed the settlement, which included the RMR agreement with the FERC. The FERC has approved the RMR agreement and we expect that the agreement will extend at least through the second quarter of 2006.

Mid-Continent Region

Our Mid-Continent generating facilities, with a total capacity of 2,445 MW, are located in the Midwest and Southeast markets. Our Mid-Continent region had a combined 2005 capacity factor of 7%. The Midwest facilities, which include our Sugar Creek and Zeeland facilities, consist of 1,372 MW of generating capacity and are all natural gas fired peaking and/or intermediate units. The Southeast includes two facilities, West Georgia and Shady Hills, with a total capacity of 1,073 MW.

Midwest. The Sugar Creek facility is a combined cycle facility with the capability to produce 535 MW. Located in West Terre Haute, Indiana, the Sugar Creek facility has the physical capability to be interconnected with either the Cinergy or American Electric Power, Inc. (AEP) systems. Cinergy is a member of the Midwest Independent Transmission System Operator (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 facility sells energy into either PJM or MISO (whichever is the best available market). When the unit runs in the PJM clearing markets, it receives a price comparable to the AEP/Dayton Hub.

The Zeeland facility, located in Zeeland, Michigan, is comprised of simple cycle units totaling 307 MW of capacity and a 530 MW combined cycle facility (837 MW of total capacity). The Zeeland facility is interconnected with the International Transmission Company, which is a member of the MISO and operated under the East Central Reliability Coordination Agreement (ECAR) which, as of January 2006, has been merged with the Mid-American Interconnected Network (MAIN) and the Mid-Atlantic Area Council (MAAC) reliability regions and is part of ReliabilityFirst, the North American Electric Reliability Council (NERC) subregion. ReliabilityFirst is the successor organization to the three NERC regional reliability councils: MAAC, ECAR and MAIN.

We have a tolling agreement for the electrical energy output (307 MW, simple cycle) from the Zeeland plant, Units 1A and 1B, which expires on May 31, 2006. The tolling agreement provides for the generation owner to provide electric energy and related services using fuel supplied by the customer or with a pass-through to the customer of actual fuel cost. We receive a monthly capacity payment, a variable operating and maintenance payment on a per megawatt hour (MWh) basis and a start-up payment each time the unit is turned on. Our counterparty provides to the Zeeland plant all the fuel required to operate the contractual portion of the plant. Mirant Zeeland, LLC (Mirant Zeeland) indirectly provides a heat rate and availability guarantee. There are bonus and penalty provisions in the agreement for availability outside allowable limits.

Mirant Zeeland Phase 2 (530 MW combined cycle output) has a tolling contract for 100% of its output through March 2006. The toll is with Mirant Energy Trading, which in turn has an agreement with a counterparty. We receive a monthly capacity payment, variable operations and maintenance payments on a per MWh basis and a start-up payment. There are heat rate and availability guarantees with associated bonuses and penalties for being outside of tolerance bands. The fuel required to operate the facility during the term of the toll is provided to Mirant Zeeland through Mirant Energy Trading s agreement with its counterparty. Mirant Zeeland operates under the MISO market and the ReliabilityFirst subregional reliability council of NERC. We are currently in negotiations to extend the Mirant Zeeland tolling agreements through the end of 2006.

For a discussion of the MISO, see Regulatory Environment United States below.

Southeast. We have two facilities in the Southeast with a total capacity of 1,073 MW. 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 approximately 605 MW and 468 MW, respectively. Currently, there is no ISO in the Southeastern Electric Reliability Council.

West Georgia Generating Company, LLC (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 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 has also 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 2014, begins 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 guarantee and receives bonuses and pays penalties when its performance is outside the guaranteed values.

West Region

Our West region facilities, with a total capacity of 3,474 MW, are primarily gas fired generating facilities located in California, Nevada and Texas. Our West region had a combined 2005 capacity factor of 17%.

California. Our generating facilities in California consist of the Pittsburg, Contra Costa and Potrero facilities, which have generation capacity of 1,311 MW, 674 MW and 362 MW, respectively, for a total capacity of 2,347 MW. The Pittsburg and Contra Costa facilities are intermediate 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 baseload steam boiler from which it generates electricity and three oil fired peaking distillate fueled combustion turbines.

The majority of our California assets are subject to RMR arrangements with the California Independent System Operator (CAISO). These agreements are described further under Regulatory Environment United States below. Our California subsidiaries currently have the largest portfolio of units which operate under RMR arrangements in California, reflecting that the location of these units makes them key to electric system reliability. In September 2005, the CAISO Board approved RMR designations for 2006 that are the same as designations for 2005. Pittsburg Unit 7 and Contra Costa Unit 6 are not subject to an RMR arrangement, and thus function solely as merchant facilities in the CAISO. Mirant Energy Trading either sells the output of Pittsburg Unit 7 and Contra Costa Unit 6 into the market through bilateral transactions with utilities and other merchant generators, or dispatches the units in the CAISO clearing markets.

Pittsburg Unit 7, which has 682 MW of generation capacity, operated pursuant to a tolling agreement with a third party that expired in December 2005. We are currently seeking proposals for a one-, two- or three-year tolling arrangement or resource adequacy capacity sale on both Pittsburg Unit 7 and Contra Costa Unit 6. If we are unable to enter into a new tolling agreement for Pittsburg Unit 7 on acceptable terms, we may retire this unit.

Nevada. The Apex generating facility, a 518 MW intermediate gas fired combined-cycle facility located near Las Vegas, Nevada, was developed by us and began commercial operations in May 2003. 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.

Texas. We have two facilities in Texas, the Bosque facility and the Wichita Falls facility. The Bosque facility consists of a gas fired combustion turbine with a corresponding steam turbine with a capacity of 230 MW that is available to serve baseload and intermediate demand. Additionally, Bosque Units 1 and 2 are gas fired peaking facilities with a capacity of 151 MW each. We have entered into a tolling agreement that grants the counterparty exclusive rights to the power and ancillary services generated by the Bosque facility through December 2006. The Wichita Falls facility is a combined cycle facility and consists of three gas turbines and a steam turbine with a total capacity of 77 MW. The Wichita Falls facility primarily sells its electrical output to the merchant market. On February 13, 2006, we executed an agreement with a third party to sell our 77 MW Wichita Falls facility. The sale is contingent upon finalizing certain closing conditions and is expected to be completed in the second quarter of 2006.

Both the Bosque and Wichita Falls facilities operate in the Electric Reliability Council of Texas (ERCOT) market. For a discussion of ERCOT, see Regulatory Environment United States below.

Philippines

We, indirectly through our Philippine subsidiaries, have ownership, long-term lease or similar interests in eight generating facilities in the Philippines. As of December 31, 2005, our net ownership interest in the generating capacity of these facilities was approximately 2,200 MW. Over 90% of the generation capacity in the Philippine facilities is sold under long-term energy conversion agreements with the Philippine government-owned National Power Corporation (NPC). NPC acts as both the fuel supplier and the energy purchaser under the energy conversion agreements for our Pagbilao, Sual and Ilijan facilities. NPC procures all of the fuel necessary for generation under an energy conversion agreement, at no cost to the respective subsidiary or affiliate, and has substantially all fuel risks and fuel related obligations under the agreement other than those relating to the fuel burning efficiency of the facility.

Under the energy conversion agreements, we receive both fixed capacity fees and variable energy fees. Fixed capacity fees compensate us for our agreement to make the facility available exclusively to NPC and 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 our revenues with respect to our Philippine operations come from fixed capacity charges. Nearly all of our capacity fees 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 Philippine government s build-operate-transfer program. At the end of the term of each energy conversion agreement, the facility is to be transferred to NPC, free from any lien or payment of compensation. The energy conversion agreement for Navotas II, a 95 MW generating facility, expired on July 31, 2005, and the facility was transferred to NPC on August 1, 2005. The energy conversion agreements for the Sual, Pagbilao and Ilijan facilities expire in October 2024, August 2025 and January 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 200 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.

Our larger Philippine projects were granted preferred or pioneer status that, among other things, qualified them for income tax holiday incentives. The income tax holiday incentive expired in June 2002 for our Pagbilao facility and in October 2005 for our Sual facility and will expire in January 2008 for our Ilijan facility. The amount of benefit from these holiday incentives is $45 million, $54 million and $50 million for 2005, 2004 and 2003, respectively.

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 15 to the consolidated financial statements contained elsewhere in this report where further discussed.

Philippine Law Changes

As part of its revenue enhancement program, the Philippine government has enacted certain changes to its existing tax law. The Expanded Value Added Tax (E-VAT) law removes tax exemptions on the sale of electricity, oil products, coal and natural gas, among others, but allows the tax to be passed on to consumers. On January 31, 2006, in accordance with the provisions of the E-VAT, the President of the Philippines raised the value added tax (VAT) rate from 10 percent to 12 percent starting February 1, 2006.

The Supreme Court of the Philippines has upheld the constitutionality of the new VAT law, and the new law became effective on November 1, 2005. There is pending legislation in the Senate and the House of Representatives that seeks to exempt oil and power products from the coverage of the E-VAT to prevent further escalation of oil and electricity prices in the country. It cannot be determined at this point what the prospects are for this legislation being passed.

The E-VAT itself does not have a negative impact on our Philippines operations. This assessment is based on the new tax law s final implementing rules and regulations as prescribed by the Bureau of Internal Revenue that allow us and other independent power producers (IPPs), including the NPC, to pass the VAT on to their consumers. However, the E-VAT does increase corporate income tax rates over the next three years (2006-2008) from 32% to 35%, which may increase the taxes paid by our Philippines operations. Starting in 2009, the corporate income tax rate will decrease to 30%.

Caribbean

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

Jamaica Public Service Company Limited (JPS)

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 for a period of twenty years. 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 (OUR) may waive the requirements for competitive tendering. JPS has installed generation capacity of 603 MW, and it purchases an additional 146 MW of firm capacity from three IPPs 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 555,000 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 indexed to inflation, changes in fuel prices, costs to purchase power and foreign exchange movements. JPS completed its most recent rate case in June 2004.

Grand Bahama Power Company (Grand Bahama Power)

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. In September 2005, a construction expansion of 18 MW was completed. 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, 2005, 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 (PowerGen)

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 the Trinidad and Tobago Electricity Commission (T&TEC), the state-owned transmission and distribution monopoly, 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 the T&TEC, which expires in 2009 and is guaranteed by the government of Trinidad and Tobago. Under this contract, the fuel is provided by the T&TEC.

On November 30, 2004, PowerGen submitted a bid to build new generation and provide electric generation capacity under long-term power purchase agreements to National Energy Corporation (NEC), a government agency responsible for infrastructure development in Trinidad, and T&TEC. On December 6, 2005, PowerGen and T&TEC executed a 30-year 208 MW power sales agreement. PowerGen began construction of the facility in February 2006 and estimates a commercial operations date of February 2007. PowerGen is currently in discussions with NEC and T&TEC to supply approximately 420 MW of additional capacity with a projected commercial operation date during the fourth quarter of 2008.

In January 2006, a new Finance Act was approved by Parliament and the Trinidad and Tobago Senate. The President of Trinidad and Tobago assented to the Finance Act on February 8, 2006. The Finance Act, upon enactment, will change the corporate income tax rate applicable to PowerGen from 30% to 25%.

Curacao Utilities Company (CUC)

We own a 25.5% interest in CUC at the Isla Refinery in Curacao, Netherlands Antilles. The 133 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, 2005, CUC was in technical default under its $97 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. In the event this 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 December preferred dividend because it is in default under its $115 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 has exercised any such options at this time.

At December 31, 2005, Aqualectra was in default under its $115 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. However, Aqualectra is current in its debt service payments under its credit facility and is engaged in discussions with its lenders with respect to its financial situation and pending defaults. An energy fund was established by the Island Council and Executive Council of the Island Territory of Curacao in December 2005 intended to stabilize the prices of the energy related products on the island for the period 2005 through 2006. The energy fund will 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. Aqualectra has recovered approximately $7 million Netherlands Antillean Guilder (ANG) (US $3.9 million) in excess fuel costs from the energy fund for 2005 and expects to recover an additional $5 million ANG (US $2.8 million) in March 2006. Aqualectra also expects to receive a waiver from the banks related to its financial covenant breaches after the receipt of the March payment from the energy fund and to pay our past due December preferred dividend at that time.

Under the terms of the Aqualectra stockholders agreement, we have the right to elect a majority of the members of the supervisory board of Aqualectra and to control the appointment of management and stockholder votes during the pendency of certain triggering events, including (i) a default under indebtedness in excess of $1 million, (ii) a failure to honor our option to require it to purchase our preferred equity interest, (iii) a failure to make two consecutive dividend payments and (iv) a failure to maintain the specified debt service ratio. Although our right to exercise additional control has been triggered, we are continuing to evaluate the situation and, to date, we have not elected to exercise such right.

Regulatory Environment

United States

The U.S. 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 generating facilities 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 sales for resale of natural gas, but does not regulate the prices received by our subsidiary that markets natural gas.

The Energy Policy Act of 2005 (EPAct 2005) became law on August 8, 2005, and it contains a wide range of provisions addressing many aspects of the electric industry. The EPAct 2005 repealed the Public Utility Holding Company Act of 1935 (PUHCA) and enacted the Public Utility Holding Company Act of 2005, which imposes on us additional obligations to maintain books and records unless we qualify for an exemption from these requirements, which is anticipated. The EPAct 2005 requires the FERC and other agencies to engage in numerous rulemakings and we are evaluating the potential impacts and opportunities that may result from these rulemakings. The EPAct 2005 authorizes the FERC to oversee new Electric Reliability Organizations that will develop and enforce national and regional reliability standards. In addition, the EPAct 2005 greatly expands the FERC s ability to impose criminal and civil penalties for violations of the Federal Power Act with a specific emphasis on market manipulation and market transparency.

The FERC has authorized our subsidiaries that constitute public utilities under the Federal Power Act to sell energy and capacity at wholesale market-based rates and has authorized some of these subsidiaries to sell certain ancillary services at wholesale 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 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, it would no longer be able to make certain sales of natural gas.

The majority of our facilities operate in ISO/RTO regions. In areas where ISOs or RTOs control the regional transmission systems, market participants have expanded access to transmission service. ISOs and RTOs also may operate real-time and day-ahead energy and ancillary services markets, which are 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 an 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, the Midwest and California have joined the existing ISO/RTO for their respective region.

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 are 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 has put in place 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.

At the state and local levels, regulatory authorities historically have overseen the distribution and sale of retail electricity 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 at the retail level in a state with a retail access program, it may be subject to state certification requirements and to bidding rules to 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 dispatches generators accordingly. 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 in 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 over the last three years to include Allegheny Power, Commonwealth Edison, AEP, Duquesne Light, Dayton Power & Light (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 will need capacity additions within the next few years.

On August 31, 2005, PJM filed its Reliability Pricing Model (RPM) with the FERC. This proposal is intended to replace its current capacity market rules. The new RPM proposal would provide for establishment of locational deliverability zones for capacity phased in over a several year period beginning on June 1, 2006. If ultimately approved by the FERC in a form not materially different from what was filed, the new RPM would result in increased opportunities for generators to receive more revenues for their capacity. However, on November 5, 2005, PJM proposed to delay the effective date of the RPM until June 1, 2007, and it is impossible to predict whether this or a similar proposal will be adopted.

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 first to 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 employs an Automated Mitigation Procedure (AMP) in its day-ahead market that automatically caps energy bids when certain established bid screens indicate a bidder may have market power. In response to a January 14, 2005, order of the U.S. Court of Appeals for the D.C. Circuit, in the spring of 2005 the NYISO discontinued use of the AMP in the upstate region known as Rest of State. In addition, 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. It is possible that 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, with a price mitigation method similar to the NYISO s AMP (discussed above), although it is implemented via manual processes rather than the automated process employed in New York. In 2004, the FERC approved a locational installed capacity market for ISO-NE (the LICAP proposal) based on the demand curve concept used by the NYISO to be implemented in January 2006. The LICAP proposal included demand curves, which are administrative mechanisms used to establish electricity generation capacity prices. A hearing on the demand curve parameters was held in February and March 2005 and an initial decision was issued by the presiding administrative law judge that found in favor of many of the suppliers issues in the hearing. A subsequent FERC order issued on October 21, 2005, pushed back the LICAP implementation date to no sooner than October 1, 2006, and put in place procedures to pursue a settlement on alternatives to the LICAP mechanism. Any such alternatives were to be submitted to the FERC by January 31, 2006. On January 31, 2006, a FERC settlement judge reported that an agreement in principle had been reached among the majority of parties in the LICAP proceeding and requested an extension of the January 31, 2006 deadline so that a final settlement could be filed with the FERC by March 6, 2006. We cannot predict if a final settlement will be filed with the FERC or if or when the LICAP proposal or any alternative proposal may be implemented or the impact any such proposal may have on our business and results of operations.

Mid-Continent Region. Our Mid-Continent plants are located in the Midwest and Southeast markets. In the Midwest markets, our facilities participate in a market administered by the MISO. The MISO commenced administering energy markets similar to those operated by PJM in the spring of 2005. The MISO uses locational marginal pricing for energy. The MISO proposes to implement a permanent solution to resource adequacy by June 1, 2007, but has not yet identified a specific capacity market design or when it will file a tariff with the FERC. The MISO also implements mitigation rules similar to those of the NYISO, without an automatic mitigation mechanism. Our Sugar Creek facility is interconnected to both the MISO and PJM, through Cinergy s and AEP s transmission systems, and can sell into either market (although not into both simultaneously). Sugar Creek is eligible to participate in the PJM capacity and energy markets.

In the Southeast, we currently sell electric energy and capacity under bilateral contracts that contain terms and conditions that are not standardized and that have been negotiated on an individual basis. Customers in this region include investor-owned, vertically integrated utilities, municipalities and electric cooperatives.

West Region. Our generation facilities in the West are located in the Western Interconnection and ERCOT market in Texas. Our California facilities are located in 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 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.

The CAISO has proposed changes to its market design to more closely mirror the Eastern ISO markets. The market redesign has been delayed several times, with full implementation now expected in 2007 or 2008. The California Public Utilities Commission (CPUC) has taken the lead role for establishing capacity requirements in California and has ordered California s load serving entities to demonstrate, beginning in the summer of 2006, that they have acquired sufficient capacity to serve their forecast retail load plus a specified reserve margin. 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 also 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 or the result of the CPUC proceeding or the timing or development of a wholesale capacity market by either the CPUC or the CAISO.

The majority of our assets in California are subject to RMR arrangements with the CAISO. These agreements require certain of our facilities, under certain conditions and at the CAISO s request, to operate at specified levels in order to support grid reliability. Under the RMR arrangements, we recover through fixed charges either a portion (RMR Contract Condition 1) or all (RMR Contract Condition 2) of the annual fixed revenue requirement of the generation assets as approved by the FERC (the Annual Requirement). Our California generation facilities operating under RMR Contract Condition 1 depend on revenue from sales of the output of the plants at market prices to recover the portion of the plant s fixed costs not recovered through RMR payments.

Our subsidiaries owning facilities subject to the RMR arrangements have entered into two PPAs with Pacific Gas & Electric (PG&E) that allow PG&E to dispatch and purchase the power output of all units of those generation facilities designated by the CAISO as RMR units under the RMR arrangements. The first agreement was in effect during 2005 and the second agreement extends from 2006 through 2012. Under those agreements, those units designated as RMR by the CAISO are designated as RMR Contract Condition 1, but during 2005 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 on an aggregate basis from those 2004 rates by $5 million. After 2008, we will file annually for FERC approval of the Annual Requirement, which, once approved by the FERC, will set the rates to be charged.

The CAISO imposed a $400 per MWh hour cap, effective on January 1, 2006, on prices for energy and has implemented an AMP similar to that used by the NYISO. 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 must-offer requirement). The practical effect of this rule is to obtain operating reserves without paying for them, and to release excess supply energy into the market, thus depressing prices. On August 26, 2005, the Independent Energy

Producers, a trade association, filed a complaint at 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. If granted by the FERC, the new RCST may result in increased capacity revenue opportunities for generators.

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 logbook standards for electricity generating facilities. In its orders, the CPUC has stated its intent to implement and enforce these detailed standards so as 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 logbook 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.

Our Texas plants participate in a market administered by ERCOT, which manages a major portion of the state s electric power grid. ERCOT oversees competitive wholesale and retail markets resulting from electricity restructuring in Texas and protects the overall reliability of the ERCOT grid. ERCOT, the only ISO that manages both wholesale and retail market operations, is regulated by the Public Utility Commission of Texas (PUCT). The PUCT conducts market monitoring within ERCOT. Price mitigation measures in ERCOT include a $1,000 per MWh price cap and RMR-type contracts for congested areas. The PUCT has recently conducted hearings on wholesale market design issues that will focus on adding a congestion management mechanism based on locational pricing, using nodal locational pricing with day-ahead and real-time markets. Presently, we cannot estimate when the enhancements will be completed and implemented.

Philippines

In June 2001, the Philippine Congress approved and passed into law the Electric Power Industry Reform Act (EPIRA), providing the mandate and the framework to introduce competition in the Philippine electricity market. EPIRA also provides for the privatization of the assets of NPC, including its generation and transmission assets, as well as its contracts with IPPs. The deregulation of the Philippine electricity industry and the privatization of NPC have been long anticipated, and EPIRA is not expected to have a material impact on our existing Philippine assets or our operations. EPIRA provides that competition in the retail supply of electricity and open access to the transmission and distribution systems was to have occurred within three years from EPIRA s effective date in June 2001. Prior to June 2002, concerned government agencies were to establish a wholesale electricity spot market, ensure the unbundling of transmission and distribution wheeling rates and remove existing cross-subsidies provided by industrial and commercial users to residential customers.

In August 2005, the Energy Regulatory Commission (ERC) of the Philippines issued a resolution reiterating the statutory mandate under the EPIRA law for generation companies to make a public offering of at least 15% of their common shares by June 2006. The ERC has not yet issued rules and regulations regarding this requirement and they are not expected to in time to allow this requirement to be met by June 2006. As a result, the ultimate impact cannot be determined.

Under EPIRA, NPC s generation assets are to be sold through transparent, competitive public bidding, while all transmission assets are to be transferred to the Transmission Company, initially a government-owned entity that is to eventually be privatized. The privatization of these NPC assets has been delayed and is considerably behind the schedule set by the Philippine Department of Energy. EPIRA also created the Power Sector Assets and Liabilities Management Corporation (PSALM), which is to accept transfers of all assets and assume all outstanding obligations of NPC, including its obligations to IPPs. One of PSALM s responsibilities is to manage these contracts with IPPs after NPC s privatization. PSALM also is responsible for privatizing at least 70% of the transferred generating assets and IPP contracts no later than three years from the effective date of the law. The work related to the planned privatization has commenced, but is considerably behind schedule.

Consistent with the announced policy of the Philippine government, EPIRA contemplates continued payment of NPC s obligations under its energy conversion agreements. The energy conversion agreements of our Philippine subsidiaries with NPC are not assignable without our consent. We are continuing discussions with NPC and PSALM on a proposal to add PSALM as an additional obligor under NPC s existing energy conversion agreements. Additionally, the Philippine government issued performance undertakings to guarantee the performance of NPC s obligations under certain energy conversion agreements.

There is new proposed legislation in the Philippines Senate that seeks to introduce changes and amendments to the EPIRA. Mirant Philippines energy conversion agreements with NPC provide change in law protection and the Republic of the Philippines has issued performance undertakings to guarantee performance of the NPC s obligations under its energy conversion agreements.

While it is our view that we have adequate contractual rights and governmental assurances to prevent any adverse financial impact to operations resulting from any amendments to EPIRA, the ultimate effect cannot be determined at this time.

Caribbean

Jamaica

Regulatory Environment. The principal activities of JPS are regulated in accordance with the terms of the License. The OUR, which was established pursuant to the Office of Utility Regulation Act of 1995, was granted authority to regulate the rates charged by JPS and its performance under the License.

All-Island Electric License. JPS operates pursuant to a 20-year License that grants it the exclusive right to transmit, distribute and supply electricity on the island of Jamaica. Upon expiration of the initial term of the License, and at the expiration of any extension, the government of Jamaica may acquire JPS s business at its fair market value, as determined by an independent valuation expert. The government of Jamaica is required to give JPS two years prior notice of its intent to acquire the business and if no such notice is given, the License will continue in force for successive ten-year terms.

If JPS fails, without just cause or excuse, to comply with any material term or condition of the License, fails to carry out with good faith or reasonable diligence its obligation under the License, or is financially impaired in its ability to perform under the License, the government of Jamaica may revoke the License and acquire JPS s business at 75% of its fair market value. Additionally, the government of Jamaica has certain step-in rights to enter and operate the electric undertaking, according to prudent utility practice, if JPS fails to operate a substantial part of its system and/or any generation facility for 48 consecutive hours without just cause.

Tariff Structure. Schedule 3 of the License defines the rates for electricity and the mechanism for rate adjustments. Under the License, the rates for electricity consist of a non-fuel base rate, which is adjusted annually for inflation and certain performance measures and a fuel rate, which is adjusted monthly to reflect fluctuations in actual fuel costs, net of adjustments for prescribed efficiency targets.

Both rates (fuel and non-fuel) are adjusted monthly to account for movements in the monetary exchange rate between the U.S. dollar and the Jamaican dollar.

These rates are determined in accordance with the tariff regime, provided that the OUR annually reviews the company s efficiency levels (system losses and heat rate) and, where appropriate, adjusts these in the tariff, primarily as it relates to fuel revenues. Under the rate schedule the Company should recover its actual fuel costs net of the prescribed efficiency adjustments through its fuel rate.

Beginning May 31, 2004, and each fifth year thereafter, JPS filed and will file with the OUR to obtain adjustment to its non-fuel base rate. The rate filing, which requires OUR approval, is based on a test year and takes into account efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment.

The OUR approved a non-fuel base rate, which became effective on July 1, 2004 and includes an embedded amount designed to allow JPS to establish a reserve against damage caused by major catastrophes of $2 million annually. The amounts that JPS sets aside each month as restricted cash under this provision are the product of this embedded rate multiplied by the actual energy sales.

Bahamas

Regulatory Environment. In 1955, the Grand Bahama government granted 639 square kilometers of the island of Grand Bahama (the Port Area) to the Grand Bahama Port Authority (the Port Authority). This grant is known as the Hawksbill Creek Agreement and has a term of 99 years. The agreement grants the Port Authority licensing and regulatory functions. Also, in accordance with the Hawksbill Creek Agreement, Grand Bahama Power Company has been granted sole right to generate and supply electric energy to the island of Grand Bahama.

The license agreement between the Port Authority and us dated April 30, 1993, says that the Port Authority will grant any reasonable request of the Company to adjust electric rates in the Port Area. Generally a request for rate increase will be granted if the increase does not exceed increases in the Consumer Price Index, the rate does not exceed the highest rate charged by other providers in the Bahamas for comparable service, and the increase is needed to recover costs due to a change in law or to provide an appropriate return for capital improvements. Approximately 85% of our customer base is in the Port Area.

In 1993, Grand Bahama Power Company entered into agreements to provide electricity to the east and west ends of Grand Bahama Island outside the Port Area. The agreement gave the Port Authority the right to adjust rates and that these rates would not exceed the rates in the Port Area. Approximately 15% of our customer base is outside the Port Area.

Tariff Structure. The Company has three major tariff categories: residential, commercial and industrial. The rates have a base component that is fixed in the tariff proceeding and a fuel surcharge component. The fuel surcharge on monthly bills is proportionately increased or decreased when the cost of fuel consumed at the Company s power plants exceeds or is less than $20 per U.S. barrel. The objective of this fuel adjustment clause is to create a pass-through of increases or decreases in the commodity price of fuel, whether captured in the $20 per barrel base or in the surcharge/rebate. Through the base component of the tariff, the Company retains the risks and benefits from variances in the heat rate.

Environmental Regulation

United States

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 operating permits. Our costs of complying with environmental laws, regulations and permits are substantial. For example, we estimate that our capital expenditures for environmental compliance will be approximately $300 million for 2006 and will be $1 billion to $1.5 billion from 2006 through 2011. Our potential capital expenditures for environmental regulation are difficult to estimate because we cannot now assess what regulations may be applicable or what costs might be associated with certain regulations. Our capital expenditures will be materially impacted if the State of Maryland passes legislation or imposes regulations that increase beyond applicable federal law the restrictions on emissions of sulfur dioxide (SO2), nitrogen oxide (NOx) and mercury, or imposes restrictions on emissions of carbon dioxide (CO2). This legislation or regulation, or similar legislation or regulations in other states or by the federal government, may render some of our units uneconomic.

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.

Acid rain program. The EPA promulgated regulations that establish cap and trade programs for SO2 emissions (the Acid Rain Program) from electric generating units in the United States. Under this system, the Acid Rain Program set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO2 allowance allocations to utilities. Each allowance permits a unit to emit one ton of SO2 during or after a specified year. Affected utility units were allocated allowances based on their historic fuel consumption and a specific emissions rate. Allowances may be bought, sold or banked. Some of our facilities have surplus allowances, and some are required to purchase additional SO2 allowances to cover their emissions and maintain compliance. The costs of SO2 allowances have increased substantially in recent years. Prior to 2004, prices generally ranged between $100 and $200 per ton. Prices rose from approximately $200 per ton to approximately $800 per ton during 2004 and to approximately $1,600 per ton in 2005. We expect to be a net purchaser of allowances for 2006. Many factors can affect the price of SO2 allowances, and we cannot be certain that the price of allowances will not increase substantially from current historical highs in future years. Depending on the actual price and number of SO2 allowances we need to buy, such costs may materially impact us. This program and other regulations requiring further reductions in SO2 emissions, such as the Clean Air Interstate Rule (CAIR) may result in our deciding to further reduce emissions at some of our facilities through new control technology. The cost of additional pollution control technology could be significant; however, it could be partially offset by the avoided cost of purchasing SO2 allowances. For additional discussion of SO2 control technology see the discussion of the CAIR below.

NOx SIP call. New NOx regulations will require a combination of capital expenditures and the purchase of emissions allowances in the future. The EPA has promulgated regulations that established emissions cap and trade programs for NOx emissions from electric generating units in most of the eastern states (the NOx SIP Call). These programs were implemented beginning May 2003 in the Northeast and May 2004 in the rest of the Eastern United States. Under these regulations, a facility receives an allocation of NOx emissions allowances. If a facility exceeds its allocated allowances, the facility must purchase additional allowances. Some of our facilities in these states have been required to purchase NOx allowances to cover emissions to maintain compliance. The cost of allowances will fluctuate in future years, and depending on the actual price and number of NOx allowances we need to buy, such costs could materially affect our operations. As a result, we may decide to reduce NOx emissions through control

technology in addition to what is already installed or planned. The cost of additional pollution control technology could be significant; however, it may be partially offset by the avoided cost of purchasing NOx allowances to operate the facility.

CAIR. In March 2005, the EPA issued the CAIR, which establishes in the Eastern United States a more stringent SO2 cap and allowance-trading program and a year round NOx cap and allowance-trading program applicable to generation facilities. These cap and trade programs would 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. Currently, we are planning to install pollution control equipment at 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 2006 through 2011. 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 over the coming years.

CAMR. The EPA promulgated the Clean Air Mercury Rule (CAMR) on March 15, 2005, which utilizes a market-based cap and trade approach under Section 111 of the Clean Air Act. It requires emissions reductions in two phases, with the first phase going into effect in 2010 and the more stringent cap going into effect in 2018. It is our view that the pollution control equipment we intend to install to comply with the CAIR should adequately reduce mercury emissions to the levels required by 2010. We cannot currently estimate the costs to comply with the reductions required by 2018, but they may be material. The CAMR has faced considerable political and legal opposition, as a result of which the EPA in October 2005 issued a notice of proposed rulemaking to reconsider certain aspects of the CAMR. The CAMR is currently being challenged in federal court. Those challenges may lead to amendments to the CAMR or passage of different mercury control legislation, which could require stricter control of mercury emissions and/or more expensive control equipment.

NSR enforcement initiative. In 1999, the Department of Justice (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 costs. These enforcement actions were broadly challenged by the industry in the courts and the EPA. We have complied with the NSR regulations as they have been interpreted in final, binding decisions. In 2001 the EPA requested information concerning some of our facilities covering a time period that predates our ownership or leasing. The challenges to the new interpretation of the NSR regulations may affect the enforcement actions, but there is no assurance that there will not be further requests or enforcement proceedings that can materially affect our 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.

For example, the Commonwealth of Massachusetts has finalized regulations to further reduce NOx and SO2 emissions from certain generation facilities and to regulate CO2 and mercury emissions for the first time. Mercury emissions reductions will be required exclusively from coal fired facilities. Portions of these regulations, which become effective in the 2005-2008 time frame, will apply to our oil fired Canal

facility in the state, will increase our operating costs and will likely necessitate the installation of additional emissions control technology.

Another example of state regulation that affects our generation facilities arises in the San Francisco Bay area, where we own generation facilities. Regional NOx emissions standards have become increasingly stringent on a specified schedule over a several year period, culminating in 2005. We continued to apply our NOx implementation plan for these facilities, which included the installation of selective catalytic reduction (SCR) emissions control equipment at our Potrero Unit 3 facility and the partial curtailment of two of our higher NOx emitting units.

In 2000, the State of New York issued a notice of violation (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, Inc. (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: (1) emissions controls consisting of SCR technology to reduce NOx emissions; (2) alkaline in-duct injection technology to reduce SO2 emissions; and (3) 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 2005-2008 timeframe. We have recognized that the 2003 Consent Decree and the new regulations, taken together with property taxes based on assessed values for our New York facilities that are far in excess of actual values and with NYISO rules that do not take into consideration the importance of the Mirant Lovett facility to the reliable supply of electricity, would have rendered the continuing operation of the Mirant Lovett facility uneconomic. It is therefore our current plan to retire the Lovett generating facility by 2008. In an effort to keep the plant operating, we are trying to negotiate agreements to reduce property taxes and to compensate Mirant Lovett for its contribution to the reliability of the electricity system, which will enable us to agree with the State of New York to make capital expenditures on environmental controls in excess of $200 million, significantly more than contemplated by the 2003 Consent Decree. The 2003 Consent Decree required Mirant Lovett to notify the state of its selected option by August 1, 2004, which date was extended by the State of New York to August 1, 2005, with subsequent extensions to February 15, 2006. On February 15, 2006, Mirant Lovett submitted a proposal to the State of New York for the installation of certain environmental controls in excess of those in the 2003 Consent Decree conditioned on execution and approval of acceptable property tax and reliability agreements. Pursuant to the Bankruptcy Court s order approving of the 2003 Consent Decree, Mirant Lovett may not enter into a binding agreement to construct the environmental controls or to elect a shutdown of the facility without first obtaining the approval of the Bankruptcy Court.

Climate change. Concern over climate change deemed by many to be induced by rising levels of greenhouse gases in the atmosphere 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 CO_2 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 (see discussion of the Regional Greenhouse Gas Initiative 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 December 20, 2005, seven states in the Northeast agreed to go forward with the implementation of a cooperative known as the Regional Greenhouse Gas Initiative (RGGI). This is the first 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 will be followed by a 10% reduction in emissions by 2019.

This initiative envisions participating states executing a memorandum of understanding and then promulgating implementing regulations based on the RGGI template. The recommended allocation scheme calls for allocation of 20% of allowances to a public benefit purpose and 5% to a regional strategic carbon fund, thereby further reducing allowances available to affected facilities. In the future, the RGGI may include other sources of greenhouse gas emissions and greenhouse gases other than CO_2. If the RGGI results in mandatory regulations in states where we have generating units, our costs of implementation may be material. New York, where we have generating units, is a participant in the RGGI. Massachusetts, where we also have generating units, originally agreed to participate but later withdrew.

On June 1, 2005, the Governor of California established greenhouse gas reduction targets for California, which would by 2010, reduce statewide greenhouse gas emissions to 2000 emissions levels; by 2020, reduce statewide greenhouse gas emissions to 1990 emissions levels; and by 2050, reduce statewide greenhouse gas emissions to 80% below 1990 levels. Implementing strategies to reach these targets will be the responsibility of a Climate Action Team, an interagency team established by the Governor. The team is led by the California EPA and is composed of high level representatives from key state agencies. This team will report to the Governor and the Legislature in early 2006.

Proposed Maryland clean power rule and other air legislative and regulatory developments. In addition to the implementation of existing requirements, there are additional environmental requirements under consideration by the federal and various state legislatures and environmental regulatory bodies. Maryland s governor announced in November 2005 that he intends to propose a Maryland Clean Power Rule, that would require deep reductions in NO_x emissions (69% reduction) by the year 2009, and in SO_2 emissions (85% reduction) and mercury emissions (70% reduction) by the year 2010, at six Maryland coal fired generation facilities, including our Chalk Point, Dickerson and Morgantown facilities. If the rulemaking proceeds according to the timing indicated by the Governor s office, that regulation would become effective in the summer of 2006. Although we have not fully evaluated the impacts of the Governor s proposed rule as announced, if adopted, it would limit our ability to acquire emissions allowances for use associated with our Maryland power facilities, and would require us to consider the economic impact of increasing substantially our capital expenditures from 2006 through 2010, which may have a material impact on us. The Governor s rule, which does not require legislative approval, is expected to be officially proposed in the first quarter of 2006 and to be the subject of administrative hearings in the early spring of 2006.

In addition to the proposed state regulations, the Maryland Legislature is in the process of moving the Health Air Act in both the Senate (SB 154) and in the House (HB 189). The House and Senate bills were introduced simultaneously on January 19, 2006. The legislation is similar to the Maryland Clean

Power Rule; however, it would require deeper reductions in NOx and SO2 in 2010 and 2015. It also requires reductions of mercury emissions by the year 2010. More importantly, unlike the Maryland Clean Power Rule, the legislation also includes mandatory reductions of CO2 emissions by 2018. The reductions would be required at all three of our Maryland coal fired generation facilities. There is currently no technology that would meet the proposed requirements for mercury and CO2, and we would have to consider running the facilities less in order to comply.

In addition to the state activities, at the federal level, the Bush Administration has submitted to Congress Clean Air Act multi-emissions reform legislation, which would promulgate a new emissions cap and trade program for NOx, SO2 and mercury emissions from generation facilities. This legislation would require generation facilities to reduce overall emissions of these pollutants by approximately 50-75% phased in during the 2008-2018 timeframe, which is similar to the types of overall reductions required under CAIR and CAMR. More stringent multi-emissions reform legislation also has been proposed in Congress by some lawmakers. If enacted as proposed, some of this legislation may materially impact us.

The EPA and the states are also in the process of implementing new, more stringent ozone and particulate matter ambient air quality standards, and the EPA s rules addressing regional haze visibility issues. The full implementation of any of these rules may result in further emissions reduction requirements for some of our facilities.

Water regulations. We are required under the Federal Water Pollution Control Act (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. It is our view that the regulations recently promulgated by the EPA to implement Section 316(b) of the Clean Water Act, will require us to incur substantial expenses in future years. These regulations address the need to require the best technology available for cooling water intake structures to minimize adverse effects on fish and shellfish. These regulations set performance standards for all existing large power plants and are intended to reduce the losses of aquatic organisms inadvertently pulled into a power plant s circulating water system. Potential compliance alternatives include using existing technologies, selecting additional fish protection technologies and using restoration measures. Over the next few years, our generation facilities subject to this cooling water intake regulation (Bowline, Canal, Kendall, Pittsburg, Contra Costa, Potrero, Chalk Point, Morgantown, Potomac River and Dickerson) will be evaluating and implementing the requirements of the 316(b) regulation by completing impingement and entrainment studies, evaluating technologies, operational measures and restoration measures. The cost of performing the studies and capital expenditures to install barriers or control devices or to implement other protective measures at three of our facilities is expected to approximate $10 million from 2006 through 2011. The cost of installing protection technologies may be material.

In early 2006, the U.S. Department of the Interior, through its Fish and Wildlife Services division (the FWS), sent a letter to the U.S. Army Corps of Engineers requesting that it reinitiate formal consultation on the biological opinion that permits Mirant Delta, LLC (Mirant Delta) to use and recycle water from the San Joaquin river for its operation of the Pittsburg and Contra Costa power plants. The formal consultation process explores the environmental impacts of Mirant Delta s water usage, including the impacts on certain species of fish in the river, and then provides directives regarding the manner in which Mirant Delta may utilize river water for cooling in the plants operations. It is our view that Mirant Delta is operating in compliance with its water usage permits and that this reopening of the formal consultation process is improper. Mirant Delta responded to the FWS, asserting that it has implemented all investigative and operational measures prescribed by the FWS to reduce the impact of its water usage on the endangered species in the San Joaquin River, and it is currently waiting for a response from the FWS to this communication.

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 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, the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (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 to remediate any groundwater or solid contamination identified by PG&E at the Pittsburg and Contra Costa generating facilities. To date, we have requested that PG&E dispose of 807 cubic yards of contaminated soil at the Potrero generating facility and they have performed such disposal. We are not aware of soil or groundwater conditions that are not covered by third party agreements or insurance policies for which we expect our remediation costs to be material.

Philippines and Caribbean

Most of our international operations are subject to comprehensive environmental regulations similar to those in the United States, and these regulations are expected to become more stringent in the future. Additionally, countries in which our subsidiaries have operations are developing increased environmental regulation of many industrial activities, including increased regulation of air quality, water quality, noise and solid waste management. These developments are discussed below.

Bahamas. In 2005, the Bahamas Environment Science and Technology Commission published draft environmental management legislation and draft final regulations for pollution control and waste management. The draft regulations control air emissions, water discharges and waste management. Prior to implementation, the draft regulations must undergo review and action by the Bahamian Parliament.

Curacao. A regulatory framework for environmental control exists in Curacao and is implemented by the Environmental Service Curacao (ESC). These regulations are implemented through the issuance of nuisance licenses to sources of pollution. The nuisance licenses regulate air emissions, water discharges, waste management and other aspects of our operations. In 2005, the ESC formed an environmental task force consisting of the ESC and local industry. Among the recommendations of the task force were certain regulatory changes, which would be subject to parliamentary action.

Jamaica. Jamaica has an established regulatory framework for environmental control administered by the National Environment and Planning Agency (NEPA). These rules cover air emissions, wastewater discharges, waste management and noise. In 2002, revisions to the air quality regulations were drafted. The draft rules require parliamentary action in order to become effective. In 2006, the NEPA issued draft regulations for wastewater and sludge disposal. These rules, once enacted, will set limits for wastewater discharges at our power plants. The draft regulations will require parliamentary approval in order to become effective.

Philippines. The Philippines has an established environmental regulatory structure administered by the Department of Environment and Natural Resources (DENR). Rules govern air emissions, water discharges, waste management, wildlife management and other aspects of our operations. The DENR implements modifications to the regulations periodically in the form of Departmental Administrative Orders (DAOs). For example, in 2005, 26 DAOs were issued.

Panay Power Corp, a subsidiary of Mirant Global Corporation, a joint venture of which Mirant (Philippines) Corporation owns 50%, did not operate flue gas desulfurizers (FGDs) and emissions monitors in 2003, 2004 and 2005 at two plants. Panay Power considers that its decision not to operate FGDs and emissions monitors was appropriate and it has received no notice of violation. However, this failure may be deemed to be a violation of Administrative Order 2001-81 of the Philippines Department of Energy and Natural Resources, which could result in a significant fine. The FGDs at the plants are now operational and Panay Power is in compliance with applicable SO_2 emissions requirements.

Trinidad. Trinidad and Tobago have an established environmental regulatory structure administered by the Environmental Management Agency (EMA). The current rules require an environmental impact assessment (EIA) of proposed development projects. Upon completion of the EIA, the EMA issues a Certificate of Environmental Clearance that places environmental limitations on the proposed project. The EMA has drafted rules controlling air emissions and water discharges. These rules require parliamentary action in order to become effective.

Over the past several years, federal, state and foreign governments and international organizations have debated the issue of global climate change and policies regarding the regulation of greenhouse gases, one of which is CO_2 emitted from the combustion of fossil fuels by sources such as vehicles and power plants. The European Union and certain developed countries ratified the Kyoto Protocol, an international treaty regulating greenhouse gases, and it became effective in 2005. None of the countries in which we or our subsidiaries presently own or operate power plants has any binding obligations under the treaty. We cannot provide assurances that such laws or regulations will not be enacted in the future in a state or country in which we own or operate power plants, and in such event the impact on our business would be uncertain but could be material.

Employees

At December 31, 2005, our corporate offices and majority owned or controlled subsidiaries employed approximately 4,550 people. This number includes approximately 540 employees in the corporate headquarters in Atlanta, approximately 1,290 employees at operating facilities in the United States, approximately 1,190 employees in the Philippines and approximately 1,530 employees in our Caribbean operations. The following details the employees subject to collective bargaining agreements:

Union	Location	Number of Employees Covered	Contract Expiration Date
International Brotherhood of Electrical Workers (IBEW) Local 1900	Maryland and Virginia	476	6/1/2010
IBEW Local 503	New York	140	6/1/2008
IBEW Local 1245	California	132	10/31/2008
IBEW Local 396	Nevada	17	7/28/2008
Utility Workers Union of America (UWUA) Local 369	Cambridge, Massachusetts	32	2/28/2009
UWUA Local 480	Sandwich, Massachusetts	51	5/31/2006
United Steel Workers Local 12502	Indiana and Michigan	27	1/1/2007
Bahamas Industrial Engineers, Managerial, and Supervisory Union(1)	Grand Bahama	33	1/1/2005
Commonwealth Electrical Workers Union(2)	Grand Bahama	134	3/31/2005
Jamaica Public Service Managers Association(3)	Jamaica	181	11/30/2004
Union of Clerical Administrative & Supervisory Employees; National Workers Union; Bustamante Industrial Trade Union(3)	Jamaica	1,123	12/31/2004

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

(2) Negotiations are ongoing and will continue into 2006. Overall, the industrial climate is stable.

(3) Negotiations are ongoing with all unions and will continue into 2006. Overall, the industrial climate is stable.

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. Additionally, if our non-unionized workforce moved toward unionization, we could be materially impacted 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 purchase 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 or on a short-term fixed price basis 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. 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 impacted 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 increased 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 which 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.

Changes in commodity prices may negatively impact 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 impact 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 hedging 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 impact 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 known 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 related 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.

Our facilities in the Philippines are exposed to significant risks as a result of their reliance on their contracts with NPC, which purchases almost all of the power generated by those facilities. These risks include political instability, changes in governmental leadership, regulation of the electricity business and the credit quality of the Philippine government. If NPC were to fail to perform its obligations under its energy conversion agreements with us, the resulting loss of cash flow and revenue would have a material adverse affect on our financial condition and results of operations.

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 impact our cash flows and results of operations, including cash flows available to us to make payments on our debt or our other obligations.

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For example, on December 16, 2005, one of the generating units at our Chalk Point facility experienced a forced outage as a result of a structural failure in one of its retired-in-place precipitators. The failure caused damage to associated ductwork. The Chalk Point facility resumed normal operations on January 17, 2006. On September 18, 2005, Unit No. 1 at the Morgantown facility experienced a forced outage in response to high turbine vibration resulting from the failure of one low pressure turbine blade. This failure required the unit to be shut down. The unit returned to service on November 18, 2005.

The accounting for our asset hedging and proprietary trading activities may increase the volatility of our quarterly and annual financial results.

We engage in asset hedging activities in order to economically hedge our exposure to market risk with respect to (1) electricity sales from our generation facilities, (2) fuel utilized by those facilities and (3) emissions allowances. We generally attempt to balance our fixed-price physical and financial 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 activities, through which we attempt to achieve incremental returns by transacting where we have specific market expertise. The derivatives from our asset hedging and proprietary trading activities are recorded on our balance sheet at fair value pursuant to Statement of Financial Accounting Standards Board (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, (SFAS No. 133). These derivatives are not 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 electricity and fuel prices. For example, for the year ended December 31, 2005, we were required to mark-to-market contracts resulting in a $17 million charge as compared to the year ended December 31, 2004, when we were required to mark-to-market contracts resulting in a $148 million gain. For a more detailed discussion of the accounting treatment of our asset hedging and proprietary trading activities, see Note 6 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 impact 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 the Company 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 regulation by federal, state and local authorities, which, among other things, restricts the discharge of pollutants into the air, water and soil, and also governs 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 CO2 regulations for which there currently is not a technical compliance solution, or if we determine the expenditures required to comply are uneconomic. For example, we currently intend to retire our Lovett generation facility in New York, in part because of substantial environmental capital expenditure requirements, starting with Unit 5 in 2007 and Units 3 and 4 in 2008. We are pursuing alternatives that would make it economically feasible for this generation facility to remain in operation, but there can be no assurances that we will be successful. Furthermore, we had planned to shut down, at least temporarily, the Kendall facility from January 2006 through December 2007, with the possibility of restarting operations in January 2008. However, the ISO-NE determined that a small part of the capacity of the Kendall facility is needed for reliability and negotiated an RMR arrangement for the facility. We may mothball the Kendall facility following the expiration of the RMR arrangement if it is not economically feasible to continue to operate the facility.

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 November 2005, Maryland s governor announced that he intends to propose a Maryland Clean Power Rule that would require deep reductions in NOx emissions by 2009 and in SO2 and mercury emissions by 2010 at six Maryland coal fired power facilities, including our Chalk Point, Dickerson and Morgantown facilities. If the rulemaking proceeds according to the timing indicated by the Governor s office, that rule would become law in the summer of 2006. Although we have not fully evaluated the impacts of the Governor s proposed rule as announced, if adopted as proposed, it would require us to increase substantially our capital expenditure requirements from 2006 through 2010 in a way that could materially and adversely affect us. We may not be able to recover incremental capital costs of compliance with new environmental regulations, which may adversely affect our financial performance and condition.

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.

The expected decommissioning and/or site remediation obligations of certain of our generation facilities may negatively impact 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 impact our cash flows and may adversely impact 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, 2005, our total indebtedness was approximately $3.7 billion. In addition, the present value of lease payments under the Mirant Mid-Atlantic leveraged leases is approximately $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 other 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.

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 credits and other inputs required to produce such power by entering into hedging transactions. These asset hedging activities generally require us to post a significant amount of collateral either in the form of cash or letters of credit. As of December 31, 2005, we had approximately $987 million of posted cash collateral and $58 million of letters of credit outstanding primarily to support our asset hedging 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.

In our efforts to hedge commodity price risk, 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 impact 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 the generation facilities. The majority of our generation is sold at market prices under the 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 impact 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. This has depressed the prices that can be charged for capacity in PJM.

Certain of our assets are located in the ERCOT market. Such assets are not generally subject to regulation by the FERC, but are subject to similar types of regulation by the PUCT.

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 our competitors. Many regulations that could be issued pursuant to the EPAct 2005 may have an adverse impact on our business.

In 2003, the Northeastern United States and parts of Canada suffered a massive blackout allegedly stemming from transmission problems originating in Ohio. In part as a result of this, the EPAct 2005 requires the FERC to select an industry self-regulatory organization which will impose mandatory reliability rules and standards. We cannot predict the impact of this on us.

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 supply of electricity, at both the wholesale and retail level. In addition, any future legislation favoring large, vertically integrated utilities and a concentration of ownership of such utilities could impact 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 unfunded 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 Employee Retirement Income Security Act of 1974 (ERISA) and some of the plans are underfunded. As of December 31, 2005, our U.S. pension plans had an unfunded accumulated benefit obligation of approximately $90 million, and an unfunded projected benefit obligation of approximately $149 million, in aggregate as calculated in accordance with Financial Accounting Standards Board (FASB) Statement No. 132R (FASB 132R), *Employers Disclosures about Pensions and Other Postretirement Benefits.* As of December 31, 2005, our non-U.S. pension plans were overfunded on an accumulated benefit obligation basis by approximately $68 million, and on a projected benefit obligation basis by approximately $51 million, in the aggregate, as calculated in accordance with FASB 132R. Unless the unfunded 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.

Changes in technology may significantly impact 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 impact 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 impacted. In addition, such an attack could impact 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 personal injury 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 hurt our financial results and materially harm 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 Lovett and Bowline generation facilities in New York are subject to disputes with local tax authorities regarding property tax assessments and with the New York State Department of Environmental Conservation (NYDEC) regarding environmental controls. We are also in discussions with the NYISO and utilities regarding an agreement that would compensate Mirant Lovett for its contribution to the reliability of the New York electric power system. The facilities are forecasted to have negative operating cash flows at their current tax valuations. Until a settlement is reached on property taxes, environmental controls and reliability that would permit economically feasible operation, our subsidiaries that own the facilities, Mirant Lovett and Mirant Bowline, LLC (Mirant Bowline), will remain in Chapter 11. The Lovett and Bowline facilities are currently in negotiations on all of these issues. Although negotiations are continuing, resolutions may not be reached in the near future or not at all. Until resolutions are reached and the companies emerge from bankruptcy, we will not have access to the cash from operations generated from these subsidiaries.

Mirant NY-Gen, which includes 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 made by Mirant Americas Inc. (Mirant Americas), with the approval of and under the supervision of the Bankruptcy Court. Mirant NY-Gen is currently discussing with the FERC appropriate remediation for a sinkhole discovered in May 2005 in the dam at the Swinging Bridge facility. We also conducted a flood study to determine downstream consequences if the maximum capacities of the reservoirs were exceeded at our New York Swinging Bridge, Rio and Mongaup generation facilities, which may cause the FERC to request that Mirant NY-Gen remediate those dams as well. Mirant NY-Gen has initiated discussions with the FERC for surrendering its permits to operate all the hydro electric facilities at Swinging Bridge, Rio and Mongaup, and expects to begin that formal process soon. It is not possible at this point to determine the cost of remediating the dam and surrendering the permits, but such costs may be substantial.

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 date of the bankruptcy filing 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 few exceptions, all claims that arose prior to our bankruptcy filing and before confirmation of the Plan 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 cannot be certain that the bankruptcy proceeding will not adversely affect our operations going forward.

Although we emerged from bankruptcy upon consummation of the Plan, we cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations going forward, including our ability to negotiate favorable terms from suppliers, hedging counterparties and others and to attract and retain customers. The failure to obtain such favorable terms and retain customers could adversely affect our financial performance.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

The following properties were owned or leased as of December 31, 2005:

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)	2005 Capacity Factor(3)
United States							
Mid-Atlantic Region:							
Chalk Point	Maryland	Intermediate/Baseload/Peaking	Natural Gas/Coal/Oil	100	2,429	2,429	31 %
Dickerson	Maryland	Baseload/Peaking	Natural Gas/Coal/Oil	100	853	853	48 %
Morgantown	Maryland	Baseload/Peaking	Coal/Oil	100	1,492	1,492	50 %
Potomac River	Virginia	Intermediate/Baseload	Coal/Oil	100	482	482	31 %
Total Mid-Atlantic					5,256	5,256	39 %
Northeast Region:							
Canal	Massachusetts	Intermediate	Natural Gas/Oil	100	1,112	1,112	50 %
Kendall	Massachusetts	Intermediate/Peaking	Natural Gas/Oil	100	256	256	59 %
Martha s Vineyard	Massachusetts	Peaking	Diesel	100	14	14	1 %
Wyman	Maine	Peaking	Fuel Oil	1.4	614	9	
Total New England(4)					1,996	1,391	51 %
Bowline	New York	Intermediate/Peaking	Natural Gas/Oil	100	1,125	1,125	12 %
Grahamsville	New York	Baseload	Hydro	100	16	16	66 %
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	25 %
Rio	New York	Intermediate/Peaking	Hydro	100	9	9	30 %
Shoemaker	New York	Peaking	Natural Gas/Jet Fuel	100	44	44	
Swinging Bridge	New York	Intermediate/Peaking	Hydro	100	12	12	14 %
Total New York				100	1,672	1,672	20 %
Total Northeast					3,668	3,063	34 %
West Region:							
Contra Costa	California	Intermediate	Natural Gas	100	674	674	6 %
Pittsburg	California	Intermediate	Natural Gas	100	1,311	1,311	6 %
Potrero	California	Baseload/Peaking	Natural Gas/Oil	100	362	362	14 %
Total California					2,347	2,347	7 %
Mirant Texas	Texas	Baseload/Peaking	Natural Gas	100	532	532	38 %
Mirant Las Vegas	Nevada	Intermediate	Natural Gas	100	518	518	38 %
Mirant Wichita Falls(5)	Texas	Peaking	Natural Gas	100	77	77	19 %
Total West					3,474	3,474	17 %
Mid-Continent Region:							
Zeeland	Michigan	Intermediate/Peaking	Natural Gas	100	837	837	8 %
West Georgia(6)	Georgia	Peaking	Natural Gas/Oil	100	605	605	2 %
Sugar Creek	Indiana	Peaking	Natural Gas	100	535	535	10 %
Shady Hills(6)	Florida	Peaking	Natural Gas	100	468	468	8 %
Total Mid-Continent					2,445	2,445	7 %
United States Total					14,843	14,238	27 %
Philippines							
Sual(7)	Philippines	Baseload	Coal	94.9	1,218	1,155	37 %
Ilijan	Philippines	Baseload	Natural Gas	20	1,200	240	
Pagbilao	Philippines	Baseload	Coal	95.7	735	704	38 %
Sangi	Philippines	Baseload/Peaking/ Standby	Coal/Oil	50	75	38	50 %
Panay	Philippines	Peaking/Intermediate/Baseload	Oil	50	71	35	61 %
Carmen	Philippines	Standby/Peaking	Heavy Fuel Oil	50	37	19	9 %
Avon River	Philippines	Peaking/Intermediate/Baseload	Oil	50	18	9	26 %
Mindoro	Philippines	Peaking/Intermediate/Baseload	Heavy Fuel Oil	50	7	3	48 %
The Philippines Total					3,361	2,203	38 %
Caribbean							

PowerGen	Trinidad and Tobago	Intermediate/Peaking/Baseload	Natural Gas	39	1,157	451	52 %
Jamaica Public Service Company Limited	Jamaica	Intermediate/Baseload/Peaking	Oil/Hydro	80	603	482	52 %
Grand Bahama Power	Bahamas	Peaking/Intermediate/Baseload	Oil	55.4	151	83	44 %
CUC	Netherlands Antilles	Baseload/Peaking	Pitch/Refinery Gas	25.5	133	34	
Caribbean Total					2,044	1,050	51 %
Total Mirant					20,248	17,491	

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Distribution Business	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	555
Visayan Electric Company, Inc	Philippines	2.0	274
Total			848

Construction Projects:

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)
Bowline expansion(8)	New York	Intermediate	Natural Gas	100	750	750
Contra Costa expansion(8)	California	Intermediate	Natural Gas	100	580	580
Nabas(9)	Philippines	Baseload	Oil	50	11	6
New Washington(9)	Philippines	Baseload	Oil	50	5	2
Points Lisas expansion(10)	Trinidad	Baseload	Natural Gas	39	208	81

(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) Total MW reflects a 1.4% ownership interest, or 8.8 MW, in the 614 MW Wyman plant.

(5) We currently expect to sell this facility in 2006.

(6) Generating plant is operated by an independent third party.

(7) Mirant will acquire the remaining 5.15% in the first quarter of 2006.

(8) We do not intend to complete these construction projects and will either sell or abandon these projects.

(9) Nabas and New Washington facilities are scheduled to be in operations pending tariff approval in 2006.

(10) On December 6, 2005, PowerGen and T&TEC executed a 30-year 208 MW power sales agreement. PowerGen began construction of the facility to produce this capacity on February 23, 2006, and estimates a commercial operations date of February 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 the Petition Date, and various dates thereafter, the Mirant Debtors filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. On August 21, 2003 and September 8, 2003, the Bankruptcy Court entered orders establishing a December 16, 2003, bar date (the Bar Date) for filing proofs of claim against the Mirant Debtors estates.

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. For example, the claims filed by the California Attorney General, PG&E, various other California parties, plaintiffs in certain rate payer class action lawsuits, the plaintiffs in certain shareholder or bondholder litigation, and Utility Choice, L.P., which are described in our 2004 Form 10-K, are among the claims that were resolved prior to confirmation of the Plan. A number of claims, however, remain unresolved.

Except for claims and other obligations not subject to discharge under the Plan and unless otherwise provided below, all claims against the Mirant Debtors estates representing obligations that arose prior to July 14, 2003, are subject to compromise under the Plan. This means that the claimant will receive a distribution of Mirant common stock, cash, or both common stock and cash in accordance with the terms of the Plan in satisfaction of the claim. As a result, the exact amount of the claim may still be litigated, but we will not be required to make any payment in respect of such litigation until a resolution is obtained, through settlement, judgment or otherwise.

As of December 31, 2005, approximately 23.5 million of the shares of Mirant common stock to be distributed under the Plan to creditors have been reserved for distribution with respect to claims that are disputed by the Mirant Debtors and have not been resolved. Under the terms of the Plan, to the extent such claims are resolved now that we have emerged from bankruptcy the claimants will be paid from the reserve of 23.5 million shares on the same basis as if they had been paid out when the Plan became effective. That means that their allowed claims will receive the same pro rata distributions of common stock, cash or both common stock and cash as previously allowed claims in accordance with the terms of the Plan. It is our view that we have funded the disputed claims reserve at a sufficient level to settle the remaining unresolved proofs of claim we received during the bankruptcy proceedings and any claims resulting from our rejection of certain contracts with PEPCO, as described below in *PEPCO Litigation*. However, 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 shareholders, and pay additional cash amounts as necessary under the terms of the Plan to satisfy such pre-petition claims. We will continue to monitor our obligations as the disputed claims are resolved. 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 are also entitled to receive additional shares of common stock to avoid dilution of their distributions under the Plan.

Our Lovett and Bowline generation facilities in New York are subject to disputes with local tax authorities regarding property tax assessments and with the NYDEC regarding environmental controls. Mirant Lovett is also in discussions with the NYISO and utilities regarding an agreement that would compensate Mirant Lovett for the contribution of the Lovett facility to the reliability of the New York electric power system. The facilities are forecasted to have negative operating cash flows at their current tax valuations. Until a settlement is reached on property taxes, environmental controls and reliability, that would permit economically feasible operation, our subsidiaries that own the facilities, Mirant Lovett and Mirant Bowline, will remain in Chapter 11. The Lovett and Bowline facilities are currently in settlement discussions on all these issues. Although negotiations are continuing, settlements may not be reached in the near future, or at all. Until such settlements are reached and the companies emerge from bankruptcy, we will not have access to the cash from operations generated from these subsidiaries. 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 made by Mirant Americas with the approval of, and under the supervision of, the Bankruptcy Court. Mirant NY-Gen is currently discussing with the FERC appropriate remediation for a sinkhole discovered in May 2005 in the dam at the Swinging Bridge facility. We conducted a flood study to determine downstream consequences if the maximum capacities of the reservoirs were exceeded at our New York Swinging Bridge, Rio and Mongaup generation facilities, and Mirant NY-Gen could be requested by the FERC to remediate those dams as well. Mirant NY-Gen has initiated discussions with the FERC for surrendering its permits to operate all the hydro electric facilities at Swinging Bridge, Rio and Mongaup, and expects to begin that formal process soon. It is not possible at this point to determine the cost of remediating the dam at Swinging Bridge and surrendering the permits, but such costs may be substantial.

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 Asset Purchase and Sale Agreement (APSA), Mirant and PEPCO entered into the Back-to-Back Agreement with respect to certain PPAs, including PEPCO s long-term PPAs with Ohio Edison and Panda-Brandywine L.P. (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 Ohio Edison PPA terminated in December 2005 and the Panda PPA runs until 2021. Under the Back-to-Back Agreement, Mirant is obligated to purchase power from PEPCO at prices that are typically higher than the market prices for power.

Mirant assigned its rights and obligations under the Back-to-Back Agreement to Mirant Americas Energy Marketing. In the Chapter 11 cases of the Mirant Debtors, PEPCO asserted that an Assignment and Assumption Agreement dated December 19, 2000, that includes as parties PEPCO and various subsidiaries of ours causes our subsidiaries that are parties to the agreement to be jointly and severally liable to PEPCO for various obligations, including the obligations under the Back-to-Back Agreement. The Mirant Debtors have sought to reject the APSA, the Back-to-Back Agreement, and the Assignment and Assumption Agreement, and the rejection motions have not been resolved. Under the Plan, the obligations of the Mirant Debtors under the APSA (including any other agreements executed pursuant to the terms of the APSA and found by the final court order to be part of the APSA), the Back-to-Back Agreement, and the Assignment and Assumption Agreement are to be performed by Mirant Power Purchase, whose performance is guaranteed by Mirant. If any of the agreements is successfully rejected, 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. That claim would then be addressed under the terms of the Plan.

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). On October 9, 2003, the United States District Court for the Northern District of Texas entered an order that had the effect of transferring the First Rejection Motion to that court from the Bankruptcy Court. In December 2003, the district court denied the First Rejection Motion. The district court ruled that the Federal Power Act preempts the Bankruptcy Code and that a bankruptcy court cannot affect a matter within the FERC s jurisdiction under the Federal Power Act, including the rejection of a wholesale power purchase agreement regulated by the FERC.

The Mirant Debtors appealed the district court s order to the United States Court of Appeals for the Fifth Circuit (the Fifth Circuit). The Fifth Circuit reversed the district court s decision, holding that the Bankruptcy Code authorizes a district court (or bankruptcy court) to reject a contract for the sale of electricity that is subject to the FERC s regulation under the Federal Power Act as part of a bankruptcy proceeding and that the Federal Power Act does not preempt that authority. The Fifth Circuit remanded the proceeding to the district court for further action on that motion. The Fifth Circuit indicated that on remand the district court could consider applying a more rigorous standard than the business judgment standard typically applicable to contract rejection decisions by debtors in bankruptcy, which more rigorous standard would take into account the public interest in the transmission and sale of electricity.

On December 9, 2004, the district court 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 have appealed the district court s December 9, 2004, decision to the Fifth Circuit.

On January 21, 2005, the Mirant Debtors filed a 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 March 1, 2005, the district court ruled that it would withdraw the reference to the Bankruptcy Court of the Second Rejection Motion and would itself hear that 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 and from the district court s March 1, 2005, order as subsequently modified described below in *PEPCO Litigation Payments to PEPCO under Back-to-Back Agreement*.

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 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 in recovering such payments, PEPCO would receive a claim in the bankruptcy proceedings for the amount recovered. Also on December 1, 2005, the Mirant Debtors filed a motion in the Bankruptcy Court to assume, assume and assign, or reject certain agreements with PEPCO and for the disgorgement of funds paid post-petition under the Back-to-Back Agreement (the Motion to Assume or Reject). This motion is pending in the Bankruptcy Court. The likely outcome of these proceedings and the previously filed motions to reject the Back-to-Back Agreement and the APSA cannot now be determined.

Payments to PEPCO under Back-to-Back Agreement. On December 9, 2004, in an effort to halt further out-of-market payments under the Back-to-Back Agreement while awaiting resolution of issues related to the potential rejection of the Back-to-Back Agreement (but prior to notice of entry of the district court s order of December 9, 2004), the Mirant Debtors filed a notice in the Bankruptcy Court stating that the Mirant Debtors were suspending further payments to PEPCO under the Back-to-Back Agreement absent further order of the court (the Suspension Notice). On January 19, 2005, the Bankruptcy Court entered an order requiring the Mirant Debtors to pay amounts due under the Back-to-Back Agreement in January 2005 and thereafter until either (1) the Mirant Debtors filed a motion to reject the APSA, (2) the Fifth Circuit issued an order reversing the district court s order of December 9, 2004, denying the motion to reject the Back-to-Back Agreement, or (3) the Mirant Debtors were successful in having the obligations under the Back-to-Back Agreement recharacterized as debt obligations. PEPCO filed an appeal of the Bankruptcy Court s January 19, 2005, order. On January 21, 2005, the Mirant Debtors filed the Second Rejection Motion.

On March 1, 2005, the district court withdrew the reference to the Bankruptcy Court of the Second Rejection Motion, dismissed PEPCO s appeal of the January 19, 2005, order of the Bankruptcy Court as moot, and ordered the Mirant Debtors to pay PEPCO all past-due, unpaid obligations under the

Back-to-Back Agreement by March 10, 2005. On March 7, 2005, the district court modified the March 1, 2005, order to delay until March 18, 2005, the date by which the Mirant Debtors were to pay past-due, unpaid obligations under the Back-to-Back Agreement. On March 16, 2005, the district court further modified its order of March 1, 2005, to clarify that the amounts to be paid by the Mirant Debtors by March 18, 2005, did not include any amounts that became due prior to the filing of the Chapter 11 cases on July 14, 2003. The Mirant Debtors have appealed the district court s March 1, 2005, order, as modified, to the Fifth Circuit. The Mirant Debtors have paid all amounts due under the Back-to-Back Agreement accruing since the Petition Date.

Potential Adjustment Related to Panda Power Purchase Agreement. At the time of the acquisition of the Mirant Mid-Atlantic assets from PEPCO, Mirant also entered into an agreement with PEPCO that, as subsequently modified, provided that the price paid by Mirant for its December 2000 acquisition of PEPCO assets would be adjusted if by April 8, 2005, a binding court order had been entered finding that the Back-to-Back Agreement violated PEPCO s power purchase agreement with Panda (the Panda PPA) as a prohibited assignment, transfer or delegation of the Panda PPA or because it effected 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 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. The Company maintains 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.

PEPCO Avoidance Action. On July 13, 2005, Mirant and several of its subsidiaries, including Mirant Mid-Atlantic and Mirant Americas Generation, 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. The likely outcome of this proceeding cannot now be determined, and the Company cannot estimate what recovery, if any, it may obtain in this action.

Plan Treatment of PEPCO. Pending a final determination of the Mirant Debtors ability to reject the APSA, the Back-to-Back Agreement, and certain other agreements with PEPCO, 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 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 resulting rejection damages claim would 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.

California and Western Power Markets

California Rate Payer Litigation. Certain of our subsidiaries are subject to litigation related to their activities in California and the western power markets and the high prices for wholesale electricity experienced in the western markets during 2000 and 2001. Various lawsuits were filed in 2000 through 2003 that asserted claims under California law based on allegations that certain owners of electricity generation facilities in California and energy marketers, including the Company, Mirant Americas Energy Marketing and our subsidiaries owning generating facilities in California, engaged in various unlawful and anti-competitive acts that served to manipulate wholesale power markets and inflate wholesale electricity prices in California. All of these suits have been dismissed by final orders except for six such suits that were filed between November 27, 2000, and May 2, 2001, in various California Superior Courts and consolidated before the Superior Court for the County of San Diego for pretrial purposes. Although the plaintiffs dismissed Mirant from those suits, they have not filed to dismiss certain of our subsidiaries that are also defendants. On October 3, 2005, the California state court dismissed those six consolidated suits on the grounds that the plaintiffs claims were barred by federal preemption as a result of the Federal Power Act. On December 5, 2005, the plaintiffs filed an appeal of the dismissal. The plaintiffs in the six consolidated suits did not file claims in the bankruptcy proceedings of our subsidiaries, and we expect that their claims are barred by the Plan now that it has become effective.

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 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 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 the Company. In addition to the claims set out in the original complaint, the amended complaint asserts claims under the Securities Act of 1933, 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 the Company s California business activities but allowed the case to proceed on the plaintiffs other claims. 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.

Shareholder Derivative Litigation. Four purported shareholders derivative suits have been filed against Mirant, its directors and certain officers of the Company. Two of those suits have been consolidated. These lawsuits allege that the directors breached their fiduciary duty by allowing the Company to engage in alleged unlawful or improper practices in the California energy markets in 2000 and 2001. The Company practices alleged in these lawsuits largely mirror those alleged with respect to the Company s activities in California in the shareholder litigation discussed above. One suit also alleges that the defendant officers engaged in insider trading. The complaints seek unspecified damages on behalf of the Company, including attorneys fees, costs and expenses and punitive damages. The captions of each of the cases follow:

Caption	Date Filed
Kester v. Correll, et al.	June 26, 2002
Pettingill v. Fuller, et al.	July 30, 2002
White v. Correll, et al.	August 9, 2002
Cichocki v. Correll, et al.	November 7, 2002

The Kester and White suits were filed in the Superior Court of Fulton County, Georgia, and were consolidated on March 13, 2003, under the name *In re Mirant Corporation Derivative Litigation*. The consolidated action has been removed by Mirant to the United States District Court for the Northern District of Georgia. The Pettingill suit was filed in the Court of Chancery for New Castle County, Delaware, and was removed by Mirant to the United States District Court for the District of Delaware. The Cichocki suit was filed in the United States District Court for the Northern District of Georgia. The order entered by the Bankruptcy Court confirming the Plan enjoins the prosecution of these actions and requires that they be dismissed. On March 8, 2006, the Bankruptcy Court entered an order compelling the plaintiffs in these actions to dismiss their complaints in accordance with the terms of the Plan. The plaintiffs in the consolidated Kester and White suits and in the Pettingill suit have filed to dismiss their complaints.

Mirant Americas Generation Bondholder Suit. On June 10, 2003, certain holders of senior notes of Mirant Americas Generation maturing after 2006 filed a complaint in the Court of Chancery of the State of Delaware*, California Public Employees Retirement System, et al. v. Mirant Corporation, et al.,* that named as defendants Mirant, Mirant Americas, Mirant Americas Generation, certain past and present Mirant directors, and certain past and present Mirant Americas Generation managers. Among other claims, the plaintiffs assert that a restructuring plan pursued by the Company prior to its filing a petition for reorganization under Chapter 11 of the Bankruptcy Code was in breach of fiduciary duties allegedly owed to them by Mirant, Mirant Americas and Mirant Americas Generation s managers. In addition, the plaintiffs challenge certain dividends and distributions made by Mirant Americas Generation prior to the Petition Date. The plaintiffs seek damages in excess of $1 billion. Mirant has removed this suit to the United States District Court for the District of Delaware. This action was stayed with respect to the Mirant entities that are defendants by the filing of the Chapter 11 proceedings of these entities. The order entered by the Bankruptcy Court confirming the Plan enjoins the prosecution of this action and requires that it be dismissed. On March 8, 2006, the Bankruptcy Court entered an order compelling the plaintiffs in this action to dismiss their complaints in accordance with the terms of the Plan.

U.S. Government Inquiries

Department of Justice Inquiries. In November 2002, Mirant received a subpoena from the DOJ, acting through the United States Attorney s office for the Northern District of California, requesting information about its activities and those of its 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 the trade press that publish natural gas or electricity spot price data. The subpoena was issued as part of a grand jury investigation. The DOJ s investigation of the reporting of inaccurate natural gas price information is continuing, and we have held preliminary discussions with DOJ regarding the disposition of this matter. The DOJ s investigation is based upon the same circumstances that were the subject of an investigation by the Commodity Futures Trading Commission (CFTC) that was settled in December 2004. As described in the Company s Annual Report on Form 10-K for the year ended December 31, 2004, in *Legal Proceedings Other Governmental Proceedings CFTC Inquiry*, Mirant and Mirant Americas Energy Marketing pursuant to the settlement consented to the entry of an order by the CFTC in which it made findings, which are neither admitted nor denied by Mirant and Mirant Americas Energy Marketing, that (1) from January 2000 through December 2001, certain Mirant Americas Energy Marketing natural gas traders (a) knowingly reported inaccurate price, volume, and/or counterparty information regarding natural gas cash transactions to publishers of natural gas indices and (b) inaccurately reported to index publishers transactions observed in the market as Mirant Americas Energy Marketing transactions and (2) from January to October 2000, certain Mirant Americas Energy Marketing west region traders knowingly delivered the false reports in an attempt to manipulate the price of natural gas. Under the settlement, the CFTC received a subordinated allowed, unsecured claim against Mirant Americas Energy Marketing of $12.5 million in the Chapter 11 proceedings. The DOJ could decide that further action against the Company is not appropriate or could seek indictments against one or more Mirant entities, or the DOJ and the Company could agree to a disposition that might involve undertakings or fines, the amount of which cannot be reasonably estimated at this time but which could be material. The Company has cooperated fully with the DOJ and intends to continue to do so.

Department of Labor Inquiries. On August 21, 2003, the Company received a notice from the Department of Labor (the DOL) that it was commencing an investigation pursuant to which it was undertaking to review various documents and records relating to the Mirant Services Employee Savings Plan and the Mirant Services Bargaining Unit Employee Savings Plan. The DOL has interviewed Mirant personnel regarding those plans. The Company intends to continue to cooperate fully with the DOL.

Environmental Matters

EPA Information Request. In January 2001, the EPA issued a request for information to Mirant concerning the air permitting and air emissions control implications under the NSR 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 the Company subsidiaries ownership and lease of those plants. Mirant has responded fully to this request. Under the APSA, PEPCO is responsible for fines and penalties arising from any violation associated with historical operations prior to the Company subsidiaries acquisition or lease of the plants. If the Mirant Debtors succeed in rejecting the APSA as described above in *PEPCO Litigation PEPCO Contract Litigation*, PEPCO may assert that it has no obligation to reimburse Mirant for any fines or penalties imposed upon Mirant for periods prior to the Company subsidiaries acquisition or lease of the plants. If a violation is determined to have occurred at any of the plants, the Company 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. If such violation is determined to have occurred after the Company s subsidiaries acquired or leased the plants or, if occurring prior to the acquisition or lease, is determined to constitute a continuing violation, the Company subsidiary owning or leasing the plant at issue would also

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be subject to fines and penalties by the state or federal government for the period subsequent to its acquisition or lease of the plant, the cost of which may be material.

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 is unenforceable, noting that it can 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 Maryland Department of the Environment, the DOJ and the EPA entered into, and filed for approval with the United States District Court for the Eastern District of Virginia, a 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 consent decree requires Mirant Potomac River and Mirant Mid-Atlantic to (1) install pollution control equipment at the Potomac River plant and at the Morgantown plant leased by Mirant Mid-Atlantic in Maryland, (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 SCR or equivalent technology at Mirant Mid-Atlantic s Morgantown Units 1 and 2 in 2007 and 2008, the consent decree does not obligate the Company s 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 consent decree is subject to the approval of the district court and the Bankruptcy Court.

The owners/lessors under the lease-financing transactions covering the Morgantown and Dickerson plants (the Owners/Lessors) objected to the proposed consent decree in the Bankruptcy Court and filed a motion to intervene in the district court action. As part of a resolution of disputed matters in the Chapter 11 proceedings, the Owners/Lessors have now agreed not to object to the consent decree, subject to certain terms set forth in the Plan and Confirmation Order.

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, the City of Alexandria asserted that emissions from the Potomac River plant exceed NAAQS for SO2, nitrogen dioxide (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 emissions 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.

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, carbon monoxide (CO) and particulate matter less than or equal to 10 micrometers (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 be mixed rapidly toward the ground resulting in higher ground level concentrations of emissions. If the modeling analysis indicates that emissions from the facility may cause exceedances of the NAAQS for SO2, NO2, CO or PM10, or exceedances of mercury compared to Virginia Standards of Performance for Toxic Pollutants, the consent order requires Mirant Potomac River to submit to the Virginia DEQ a plan and schedule to eliminate and prevent such exceedances on a timely basis. Upon approval by the Virginia DEQ of the plan and schedule, the approved plan and schedule is to be incorporated by reference into the consent order. The results of the computer modeling analysis showed 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. In response to a directive from the Virginia DEQ, Mirant Potomac River temporarily shut down the Potomac River plant on August 24, 2005, pending identification and implementation of modifications to the plant or its operations, which modifications could be material. On September 21, 2005, Mirant Potomac River commenced partial operation of one unit of the plant. The financial and operational implications of the discontinued or limited operation of the Potomac River plant or any such modifications are not known at this time, but could be material depending on the length of time that operations are discontinued or limited.

On August 24, 2005, power production at all five units of Potomac River was temporarily halted in response to a directive from the Virginia DEQ. The decision to temporarily shut down the facility arose from findings of a study commissioned under an agreement with the Virginia DEQ to assess the air quality in the area immediately surrounding the facility. The Virginia DEQ s directive was based on results from the study s computer modeling showing that air emissions from the facility have the potential to contribute to localized, modeled exceedances of the health-based NAAQS under certain unusual conditions. 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, respectively. On December 20, 2005, due to a determination by the DOE that an emergency situation exists with respect to a shortage of electric energy, the DOE ordered Mirant Potomac River to generate electricity at the Potomac River generation 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. The DOE required Mirant Potomac River to submit a plan, on or before December 30, 2005, that met this requirement and did not significantly contribute to NAAQS exceedances. The DOE advised that it would consider Mirant Potomac River s plan in consultation with the EPA. 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 the rehearing requests further. 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 immediate operation of one baseload unit and two cycling units, making it possible to bring the entire plant into service within approximately 28 hours. The DOE s order expires after September 30, 2006, but we expect we 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 addresses NAAQS issues. The EPA also asserts 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 facility. The facility will not resume normal operations until it can satisfy the requirements of the Virginia DEQ and the EPA with respect to NAAQS, unless, for reliability purposes, it is required to return to operation by a governmental agency having jurisdiction to order its operation. On January 9, 2006, the FERC issued an order directing PJM and PEPCO to file a long-term plan to maintain adequate reliability in the Washington D.C. area and surrounding region and a plan to provide adequate reliability pending implementation of this long-term plan. On February 8, 2006, PJM and PEPCO filed their proposed reliability plans. We are working with the relevant state and federal agencies with the goal of restoring all five units of the facility to normal operation in 2007.

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 asserts nuisance claims, alleging that the Potomac River plant s emissions of coal dust, fly ash, 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 seeks 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.

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 s failure 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 violates 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 attorney s 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 Lovett Coal Ash Management Facility. On July 8, 2004, the New York State Department of Environmental Conservation (NYSDEC) issued an NOV for improper closure of the coal ash management facility (CAMF) at the Lovett plant. The Notice of Violation identified two separate issues. The first was the failure of the previous owner/operator of the CAMF to obtain a closure certification for Stage 1 of the CAMF that conformed with applicable New York regulations. It is our view that we have submitted documentation demonstrating that the CAMF was properly closed, however that issue is still in dispute. The second issue relates to the closure of Stage 2 of the CAMF in 2002. Erosion of the barrier protection layer and topsoil developed within a few years of the closure of Stage 2. On November 8, 2005, the NYSDEC issued an additional notice of violation to Mirant Lovett asserting that the leachate collection system for the Lovett CAMF was not properly constructed because it allows storm water or groundwater to come into contact with the disposed wastes and leachate. Due to the ongoing evaluation to determine what remedial actions are required, the exact cost of remedial action is unknown at this time.

New York Dissolved Oxygen. On September 29, 2003, the NYSDEC issued a complaint to Mirant New York for alleged failure to comply with state regulatory standards for minimum dissolved oxygen in the Mongaup River at the Swinging Bridge, Mongaup Falls and Rio hydroelectric projects owned by

Mirant NY-Gen. The complaint sought a civil penalty of $120,000 and an order requiring Mirant New York to upgrade the three hydroelectric projects to prevent further discharges that do not meet the standards for minimum dissolved oxygen. In its complaint the NYSDEC proposed that $100,000 of the $120,000 penalty it was seeking be suspended on the condition that Mirant New York complete corrective actions for each facility by a certain schedule it proposed. On June 1, 2004, Mirant New York filed an answer and motion to dismiss on grounds including that Mirant New York is not the owner of the hydroelectric projects. Mirant New York granted an extension of time to allow the NYSDEC to respond, and the NYSDEC has not yet responded. Mirant NY-Gen, the owner of the hydroelectric projects, has agreed with the NYSDEC upon a consent order to resolve the complaint. Under the consent order, Mirant NY-Gen will pay a fine of $8,000 and install certain specified equipment on the operational turbine at the Swinging Bridge facility. The specified equipment already has been installed on the Mongaup Falls and Rio facilities. In addition, Mirant NY-Gen is required to install this same equipment at the other, currently non-operational turbine at the Swinging Bridge facility within thirty days of that turbine becoming operational. The Bankruptcy Court approved the settlement on February 22, 2006, and the parties are proceeding to execute the consent order.

Mirant Bowline Oil Storage NOV. On January 4, 2006, the NYSDEC issued an NOV asserting various violations of regulations relating to a major oil storage facility, secondary containment, compliance report, underground storage tanks and a small oil storage facility at the Bowline plant. The NOV identified issues with labeling, maintenance and monitoring procedures and leak detection. The NOV did not seek a specific penalty amount but noted that the violations identified could each subject Mirant Bowline to a civil penalty of up to $37,500 per day. Mirant Bowline is working with the NYSDEC to address the issues identified.

Mirant Bowline Oil Spill. In November 2001, Mirant Bowline removed two underground oil storage tanks that had been used to collect oil recovered from the oil/water separators that are used for pretreatment of wastewater from the Bowline generating facility. Contaminated soil was found during the removal of one of the tanks and was removed from the site. Mirant Bowline is unable to confirm from documents at the facility whether the spill was reported to the NYSDEC and Rockland County, New York authorities. Consequently, Mirant Bowline reported a potential non-reported spill to the NYSDEC on February 23, 2006.

Morgantown Particulate Emissions. On March 3, 2006, Mirant Mid-Atlantic received a notice sent on behalf of the Maryland Department of the Environment (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.

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 to 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 revocation, 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 seeks 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 asserts, 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 request 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.

Other Legal Matters

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

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

Prior to July 15, 2003, old Mirant s common stock was listed under, and traded on, the New York Stock Exchange (NYSE). As a result of old Mirant s bankruptcy filing on July 15, 2003, its common stock was suspended from trading by the NYSE and, thereafter, delisted by the NYSE. Old Mirant s stock was quoted in the Pink Sheets Electronic Quotation Service (Pink Sheets) maintained by Pink Sheets, LLC for the National Quotation Bureau, Inc. from July 16, 2003, until the emergence date of January 3, 2006. The ticker symbol MIRKQ was assigned to its common stock for over-the-counter quotations.

The following table sets forth the quarterly high and low bid quotations for old Mirant s common stock as reported on the Pink Sheets for 2004 and 2005. These quotations reflect inter-dealer prices, without retail markup, markdown or commissions, and may not necessarily represent actual transactions.

	Market	High	Low
2004			
First Quarter	Pink Sheets	$0.75	$0.40
Second Quarter	Pink Sheets	0.40	0.26
Third Quarter	Pink Sheets	0.48	0.30
Fourth Quarter	Pink Sheets	0.41	0.31
2005			
First Quarter	Pink Sheets	$0.48	$0.25
Second Quarter	Pink Sheets	0.51	0.29
Third Quarter	Pink Sheets	1.46	0.63
Fourth Quarter	Pink Sheets	1.51	1.16

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. 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. 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. As of March 3, 2006, there are 101,754 registered shareholders of New Mirant common stock.

Common stock of New Mirant is currently traded on the NYSE and has been assigned the ticker symbol MIR. Our Chief Executive Officer expects to provide a certification to the NYSE that he is not aware of any violation by us of the NYSE corporate governance listing standards. The high and low sales prices for our new common stock since listing on January 11, 2006, through March 3, 2006, are:

High	$29.00
Low	$23.93

All of 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 of 1933, as amended, and equivalent provisions of state securities laws, in reliance upon Section 1145(a) of the Bankruptcy Code. As of March 3, 2006, there were 300,000,000 shares of the registrant s Common Stock, $0.01 par value per share outstanding.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table indicates the compensation plans under which equity securities of Mirant were authorized for issuance as of December 31, 2005:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	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)
Equity compensation plans approved by security holders	12,996,209	$ 13.34	N/A (1)
Equity compensation plans not approved by security holders			
Total	12,996,209	$ 13.34	N/A (1)

(1) Pursuant to the Plan, these options were canceled on January 3, 2006.

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 cash dividends on our common stock in the foreseeable future.

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. The financial information for the periods prior to our separation from Southern Company on April 2, 2001, does not necessarily reflect what our financial position and results of operations would have been had we operated as a separate, stand-alone entity during those periods.

From the Petition Date through emergence, our consolidated financial statements were prepared in accordance with Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code (SOP 90-7). Our Statement of Operations Data for the years ended December 31, 2004 and 2003 does not include interest expense on debt that was subject to compromise subsequent to the Petition Date. Our Statement 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.

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

	Years Ended December 31, 2005	2004	2003	2002	2001
	(In millions except per share data)				
Statement of Operations Data:					
Operating revenues	$ 4,184	$ 4,571	$ 5,158	$ 4,697	$ 7,202
(Loss) income from continuing operations	(1,284)	(406)	(3,633)	(2,343)	462
Loss from discontinued operations	(7)	(70)	(173)	(95)	(53)
Cumulative effect of changes in accounting principles	(16)		(29)		
Net (loss) income	(1,307)	(476)	(3,835)	(2,438)	409
Pro forma earnings per share(1)	$ (4.36)	$ (1.59)	$ (12.78)	$ (8.13)	$ 1.36

(1) Calculated by dividing our net loss attributable to common shareholders by the 300 million common shares of New Mirant stock to be issued pursuant to the Plan.

	Years Ended December 31, 2005	2004	2003	2002	2001
Balance Sheet Data:					
Total assets	$ 12,912	$ 11,424	$ 12,123	$ 19,423	$ 22,043
Total long-term debt	3,701	1,375	1,538	8,822	8,435
Liabilities subject to compromise	18	9,217	9,077		
Company obligated mandatorily redeemable securities of a subsidiary holding solely parent company debentures				345	345
Stockholders equity (deficit)	3,856	(1,318)	(823)	2,955	5,258

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

This section is intended to provide the reader with information that will assist in understanding our 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 an international energy company whose revenues are primarily generated through the production of electricity in the United States, Philippines and Caribbean. On July 14, 2003 (the Petition Date), and various dates thereafter, Mirant and 83 of its direct and indirect subsidiaries in the United States (collectively, the Mirant Debtors) filed with the United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division (the Bankruptcy Court) voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code (as amended the Bankruptcy Code). We continued to operate our business as a debtor-in-possession under the jurisdiction of the Bankruptcy Court in accordance with Chapter 11 of the Bankruptcy Code. As a result, our financial statements include the results of Bankruptcy Court bankruptcy process.

Our Plan of Reorganization (the Plan) was confirmed by the Bankruptcy Court on December 9, 2005, and we emerged from bankruptcy on January 3, 2006. As a result, we recorded the effects of the Plan in our financial statements for the year ended December 31, 2005. We recognized a gain of $283 million, included in reorganization items, net related to the effects of the Plan. Among other things we recognized the cancellation of old common stock, issuance of new common stock, reinstatement of certain debt and settlement amounts of claims, all as prescribed by the Plan. See Note 3 to our consolidated financial statements contained elsewhere in this report for additional discussion of the key elements of the Plan and the impacts of the Plan on our financial statements for the year ended December 31, 2005.

The primary factors impacting the earnings and cash flows of our United States operations are the prices for power, natural gas 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 1990 s has created an oversupply situation in most markets which is expected to continue until 2008 to 2010. The imbalance between supply and demand, price controls during periods of high demand and local constraint and lack of appropriate compensation for locational capacity value limit our ability to recover our fixed costs such that we must rely almost entirely on energy gross margins produced by generating electrical energy for a price greater than the cost of the fuel required to run the plants. 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 impacted significantly by available generating capacity, transmission capacity and federal and state regulation. We also are impacted by the relationship between prices for power and fuel, such as natural gas, coal and oil that impact our cost of generating electricity.

We engage in asset hedging activities to economically hedge our positions in order to reduce our exposure to commodity price fluctuations and to achieve acceptable gross margins. In general, we currently economically hedge a substantial portion of our Mid-Atlantic coal fired generation and our New England oil fired generation through over-the-counter transactions. However, we generally do not hedge most of our cycling and peaking capacity due to the limited value we can extract in the marketplace and the high cost of collateral typically required to support these contracts. Many of the power and fuel contracts that we use to economically hedge our portfolio meet the criteria of a derivative and are accounted for at fair value in our consolidated balance sheets. Changes in the fair value represent unrealized gains and losses and result in income volatility when the underlying energy prices are volatile.

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 operating permits. Our costs of complying with environmental laws, regulations and permits are substantial. We estimate that our capital expenditures for environmental compliance will be approximately $300 million for 2006 and will be $1 billion to $1.5 billion for 2006 through 2011. Our potential capital expenditures for environmental regulations are difficult to estimate because we cannot now assess what regulations may be applicable or what costs might be associated with the regulation. Our actual capital expenditures will be materially impacted if the State of Maryland passes legislation or imposes regulations that increase beyond applicable federal law the restrictions on emissions of SO_2, NO_x and mercury, or imposes restrictions on emissions of CO_2. This legislation or regulation, or similar legislation or regulation in other states or by the federal government, may render some of our units uneconomic.

A significant 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 Philippine operations include generating companies with long-term contracts, primarily with the Philippine government-owned NPC, which provide stable earnings and cash flow. Our core initiatives for our Philippine business include continuing to perform on our NPC contracts, managing regulatory, political and customer relationships and expanding our energy supply business from available, but uncontracted, generation capacity.

Our Caribbean operations include integrated utilities and generating companies with long-term contracts in cooperation with local governments. Our core initiatives for our Caribbean businesses include managing regulatory, political and customer relationships, reducing the system electricity losses at JPS as part of our continuous improvement efforts and adding additional generation capacity.

Consolidated Financial Performance

We reported operating income of $418 million for the year ended December 31, 2005, and operating losses of $14 million and $2,865 million for the years ended December 31, 2004 and 2003, respectively. The change in operating income is detailed as follows (dollars in millions):

	2005 versus 2004 Increase/(Decrease)		**2004 versus 2003 Increase/(Decrease)**	
Gross margin(1)	$ (198)	(10.1)%	$ (22)	(1.1)%
Operations and maintenance	13	1.3 %	82	7.6 %
Depreciation and amortization			32	9.4 %
Goodwill impairment losses(2)	582		1,485	71.8 %
Long-lived asset impairment losses(3)			1,339	
Other impairment losses and restructuring charges			34	59.6 %
Loss on sales of assets, net(4)	35	66.0 %	(99)	
Change in operating income	$ 432		$ 2,851	99.5 %

(1) For the years ended December 31, 2005, 2004 and 2003, our gross margin included the following (in millions):

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Realized gross margin	$ 1,762	$ 1,460	$ 302	$ 1,460	$ 1,674	$ (214)
Transition power agreement (TPA) amortization	9	344	(335)	344	426	(82)
Unrealized gross margin:						
Unrealized gains on Back-to-Back Agreement	98	168	(70)	168	171	(3)
Net unrealized losses on asset management and proprietary trading	(115)	(20)	(95)	(20)	(297)	277
Net unrealized gross margin	(17)	148	(165)	148	(126)	274
Total gross margin	$ 1,754	$ 1,952	$ (198)	$ 1,952	$ 1,974	$ (22)

(2) In 2004, we wrote off the remaining goodwill amounts related to our Philippine business of $582 million. In 2003, we wrote off all goodwill related to our United States business of $2,067 million. See Critical Accounting Policies and Estimates and Note 8 to our consolidated financial statements contained elsewhere in this report.

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(3) In 2003, we had a long-lived asset impairment charge of $1,339 million related to turbines, power islands and other project costs. This asset impairment also caused depreciation and amortization expense to decrease in 2004 compared to 2003.

(4) Included in loss on sales of assets, net for 2005 is an $18 million loss related to the sale of assets at one of our suspended construction projects. In 2004, we had a loss on sales of assets, net of $65 million, primarily related to the planned sale of three natural gas combustion turbines offset by a gain of $16 million on the sale of our remaining Canadian natural gas transportation contracts and certain natural gas marketing contracts. In 2003, we had a gain on sale of assets of $46 million primarily related to the sale of gas storage contracts in our Canadian trading operations.

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 impacted our consolidated financial statements. As a result, our historical financial performance is likely not indicative of our financial performance post-bankruptcy.

At December 31, 2005, we have accrued for disputed and contingent claims using our best estimate of the amount these claims will ultimately settle for. To the extent such claims are resolved post-emergence, the claimants will be paid on the same basis as if they had been paid out of the bankruptcy. That means that their allowed claims will be adjusted to the same recovery percentage as other creditors in the same class would have received and will be paid in pro rata distributions of cash and common stock in accordance with the terms of the Plan. It is our view that we have accrued the reserve at a sufficient level to settle the remaining unresolved claims. However, to the extent the aggregate amount of these payouts of contingent and disputed claims ultimately exceeds the amount of the claims reserve, we may be obligated to provide additional cash or stock to the claimants. This may also result in charges to future income or expense. For further discussion, see Critical Accounting Policies and Estimates.

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. Historically, we had managed our business as two operating segments: North America and International. In the fourth quarter of 2005, we began managing our business through the following three operating segments: United States, Philippines and Caribbean.

Beginning January 1, 2004, we changed our allocation methodology related to our corporate overhead expenses. As a result, substantially all of our corporate operating expenses are allocated to our United States, Philippines and Caribbean segments. The new methodology allocates costs using several methods but is primarily based on gross margin, property, plant and equipment balances and labor costs.

United States

Our United States segment consists primarily of electricity generation (approximately 14,000 MW of generating capacity) and energy trading and marketing activities managed as a combined business. The following table summarizes the operations of our United States segment for the years ended December 31, 2005, 2004, and 2003 (in millions):

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Gross margin	$ 971	$ 1,196	$ (225)	$ 1,196	$ 1,222	$ (26)
Operating expenses:						
Operations and maintenance	726	727	(1)	727	699	28
Depreciation and amortization	167	164	3	164	199	(35)
Goodwill impairment losses					2,067	(2,067)
Long-lived asset impairment losses					1,338	(1,338)
Impairment losses and restructuring charges	13	9	4	9	19	(10)
Loss (gain) on sales of assets, net	19	50	(31)	50	(38)	88
Total operating expenses	925	950	(25)	950	4,284	(3,334)
Operating income (loss)	$ 46	$ 246	$ (200)	$ 246	$ (3,062)	$ 3,308

In the tables below, the Mid-Atlantic region includes our Morgantown, Chalk Point Units 1-4, and Dickerson facilities. The Northeast region includes our New England and New York facilities. West and eliminations includes Mirant Texas, Mirant California and the elimination of intercompany transactions between Mirant Americas Generation subsidiaries that occurs at the Mirant Americas Generation level. Other United States generation includes Mirant Potomac River, LLC (Mirant Potomac River), Mirant Peaker, LLC (Mirant Peaker), Mirant Las Vegas, LLC (Mirant Las Vegas), Mirant Zeeland, West Georgia Generating Company, LLC (West Georgia), Mirant Sugar Creek, LLC (Mirant Sugar Creek) and Shady Hills Power Company, LLC (Shady Hills).

The following table summarizes capacity factor (average percentage of full capacity used over a year) by region for our United States segment for the years ended December 31, 2005, 2004 and 2003:

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Mirant Americas Generation:						
Mid-Atlantic	44 %	44 %	%	44 %	45 %	(1)%
Northeast	34 %	33 %	1 %	33 %	31 %	2 %
West	13 %	19 %	(6)%	19 %	9 %	10 %
Other United States generation	14 %	13 %	1 %	13 %	14 %	(1)%
Total United States	27 %	28 %	(1)%	28 %	23 %	5 %

The following table summarizes power generation volumes by region for our United States segment for the years ended December 31, 2005, 2004 and 2003 (in gigawatt hours):

	Years Ended December 31, 2005	2004	Increase/ (Decrease)	2004	2003	Increase/ (Decrease)
Mirant Americas Generation:						
Mid-Atlantic	16,572	16,463	109	16,463	16,884	(421)
Northeast	9,184	8,831	353	8,831	8,492	339
West	3,289	4,807	(1,518)	4,807	4,062	745
Other United States generation	5,032	4,815	217	4,815	5,637	(822)
Total United States	34,077	34,916	(839)	34,916	35,075	(159)

2005 versus 2004

Gross Margin. Our gross margin decreased by $225 million in 2005 compared to 2004. The following table details gross margin by realized and unrealized margin for the year ended December 31, 2005 and 2004 (in millions):

	Year Ended December 31, 2005 Realized	Unrealized	Total	Year Ended December 31, 2004 Realized	Unrealized	Total
Mirant Americas Generation:						
Mid-Atlantic	$ 478	$ (96)	$ 382	$ 499	$ (75)	$ 424
Northeast	225	(11)	214	218	31	249
West and eliminations	142		142	149	3	152
Total Mirant Americas Generation	845	(107)	738	866	(41)	825
Other United States generation	181	(1)	180	191	(21)	170
TPA amortization	9		9	344		344
Other, including TPAs and Back-to-Back Agreement	(47)	91	44	(353)	210	(143)
Total	$ 988	$ (17)	$ 971	$ 1,048	$ 148	$ 1,196

The following table summarizes the change in realized and unrealized gross margin for the year ended December 31, 2005 compared to same period in 2004 (in millions):

	Increase/(Decrease) for Years Ended December 31, 2005 versus 2004 Realized	Unrealized	Total
Mirant Americas Generation:			
Mid-Atlantic	$ (21)	$ (21)	$ (42)
Northeast	7	(42)	(35)
West and eliminations	(7)	(3)	(10)
Total Mirant Americas Generation	(21)	(66)	(87)
Other United States generation	(10)	20	10
TPA amortization	(335)		(335)
Other, including TPAs and Back-to-Back Agreement	306	(119)	187
Total	$ (60)	$ (165)	$ (225)

The $225 million decrease in gross margin is detailed as follows (in millions):

	Mid-Atlantic	Northeast	West and eliminations	Other Generation	TPA/Back-to-Back	Other	Total
Market prices-power	$ 518	$ 290	$	$ 84	$	$	$ 892
Market prices-fuel	(132)	(188)		(55)			(375)
Ancillary services	40	2		4			46
Generation volumes	(30)	(11)		(25)			(66)
Realized economic hedges	(414)	(71)	(10)	(30)			(525)
Installed capacity, RMR and tolling agreements	(6)	(2)	(32)	15			(25)
Emissions allowances	(9)	(9)	19	(5)			(4)
Unrealized gains/losses	(21)	(42)	(3)	20	(70)	(49)	(165)
TPA/Back-to-Back Agreement					244		244
TPA amortization					(335)		(335)
Other	12	(4)	16	2		62	88
Total	$ (42)	$ (35)	$ (10)	$ 10	$ (161)	$ 13	$ (225)

Mid-Atlantic operations gross margin decreased $42 million primarily due to the following:

- an increase of $518 million driven by higher market prices for power. Spot market prices for power were higher during the year ended December 31, 2005, compared to the same period in 2004. Average settlement prices increased 63%;

- a decrease of $132 million related to higher fuel prices during the period. Average prices for fuel increased as follows: gas 57%, coal 16% and oil 62%;

- an increase of $40 million related to an increase in prices for ancillary services, consistent with increased energy prices;

- a decrease of $30 million related to generation volumes. Volumes increased by 0.7%, which had a favorable effect of $3 million on gross margin based on average revenue and fuel costs per MWh in 2004. This was offset by an unfavorable impact of $33 million due to a change in the mix of generation, with increases in volumes by the more expensive gas and oil fired units and a slight decrease in the generation volumes by the coal fired units. Volumes were impacted by significant unplanned outages primarily related to baseload units;

- a decrease of $414 million due to losses on economic hedges compared to 2004 related primarily to the impact of rising energy prices on the realized economic hedges of our generation output during the 2005 period;

- a decrease of $6 million related to a reduction in revenue due to lower prices for installed capacity as a result of the expansion of the PJM market;

- a decrease of $9 million due to increased emissions expense of $14 million, partially offset by higher emissions revenue of $5 million. Prices for SO2 and NOx emissions allowances increased in 2005 compared to the same period in 2004;

- a decrease of $21 million related to losses of $96 million in the year ended December 31, 2005 on unrealized derivative contracts for future years, compared to losses of $75 million for the same period in 2004. As power prices increased during 2005, we recognized losses on short power positions used to hedge the expected output of our power plants in future years. These losses on unrealized power hedges were greater in 2005 than in 2004, but were partly offset by the settlement

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of hedges that had a negative value at the start of the year and by a gain in 2005 on unrealized fuel hedges for future years, compared to a loss for the same period in 2004; and

- an increase of $12 million in other primarily due to a $13 million net settlement with a coal supplier related to rail car transportation schedule issues that resulted in lower fuel expense.

Northeast operations gross margin decreased $35 million primarily due to the following:

- an increase of $290 million driven by higher market prices for power. Spot market prices for power were higher during the year ended December 31, 2005 compared to the same period in 2004. Average settlement prices increased 63% in New York and 49% in New England. In 2005, we received $5 million from the NYISO related to adjustments from 2000-2003;

- a decrease of $188 million related to higher fuel prices during the period. Average prices for fuel in New York increased as follows: gas 37%, coal 25%, and oil 56%. Residual oil prices increased 48% and gas prices increased by 42% in New England;

- an increase of $2 million related to an increase in prices for ancillary services, consistent with increased energy prices;

- a decrease of $11 million related to an increase in generation volumes. This incremental generation has a favorable impact of $5 million on gross margin, which is offset by an unfavorable variance of $16 million due to a change in the mix of generation, with increases in volumes by the more expensive gas fired units and a slight decrease in the generation volumes by the coal fired units;

- a decrease of $71 million related primarily to the impact of rising energy prices on the realized economic hedges of our generation output, partly offset by the impact of rising fuel prices on the realized economic hedges of our fuel requirements during the period;

- a decrease of $2 million that reflects lower revenues at New York of $11 million due to lower prices for installed capacity. This was partially offset by increased revenues in New England of $9 million due to the Kendall RMR agreement;

- a decrease of $9 million due to reduced sales of surplus emissions allowances to the Mid-Atlantic facilities;

- a decrease of $42 million related to losses of $11 million in the year ended December 31, 2005 on unrealized derivative contracts for future periods, compared to a gain of $31 million for the same period in 2004. As power prices increased during 2005, we recognized losses on power sales contracts used to hedge the expected output of our power plants in future years. These losses on unrealized power hedges for future periods were greater in 2005 than in 2004, but were partly offset by increased gains on unrealized fuel hedges for future periods. In addition, the hedges settled in 2005 had a net favorable value at the beginning of the year and this contributed to the reduction in value of unrealized derivative contracts. In 2004 the settlement of hedges with a net unfavorable value at the beginning of 2004 had the effect of increasing the value of derivative contracts for future periods; and

- a decrease of $4 million in other which includes a decrease in gas sales and transport of $6 million offset by additional receipts in 2005 of $5 million in insurance proceeds related to an outage at the Bowline facility in 2004, compared to $2 million of proceeds received in 2004.

West and eliminations operations gross margin decreased $10 million primarily due to the following:

- a decrease of $10 million related to reduced merchant generation and realized economic hedge activity;

- a decrease of $32 million related to the expiration of an RMR contract for one of our California generating facilities in 2004 partially offset by capacity income from tolling agreements on those California assets not covered by RMR and our facility in Texas;

- an increase of $19 million due to the elimination of a gain on intercompany SO2 emissions allowances transfers in 2004 and the elimination of the related expense recorded in 2005;

- a decrease of $3 million related to a decrease in net unrealized gains on derivative contracts for future periods; and

- an increase of $16 million in other primarily due to lower gas transport costs and reduced losses on gas sales. Under the new power purchase agreements entered into early in 2005, PG&E is responsible for purchasing the fuel for most of the California units. See Item 1. Business for further discussion.

Other generation gross margin increased $10 million primarily due to the following:

- an increase of $84 million driven by higher market prices for power. Spot market prices for power were higher during the year ended December 31, 2005 compared to the same period in 2004. Average settlement prices increased 45% at Mirant Potomac River, 78% at Mirant Peaker and 37% at Mirant Las Vegas;

- a decrease of $55 million related to higher fuel prices during the period. Average prices for coal increased by 33% at Mirant Potomac River, oil prices increased 37% at Mirant Peaker and gas prices increased 41% at Mirant Las Vegas;

- an increase of $4 million related to increases in prices for ancillary services, consistent with increased energy prices;

- a decrease of $25 million related to decreased volumes, primarily at the Potomac River plant due to the shutdown from August to December 2005 of all but one of our units by the Virginia DEQ. See Item 1. Business for further discussion;

- a decrease of $30 million related primarily to the impact of rising energy prices on the realized economic hedges of our generation output during the period;

- an increase of $15 million related to capacity income from tolling agreements at the Zeeland and the Las Vegas facilities;

- a decrease of $5 million due to an increase in net emissions allowance expense; and

- an increase of $20 million related to lower net unrealized losses on derivative contracts for future periods.

Non-cash revenue related to the amortization of the TPAs decreased by $335 million and realized gross margin related to the TPAs increased $226 million primarily due to the expiration of one of the Maryland TPAs in June 2004 and the expiration of the D.C. TPA in January 2005. Realized margin related to the Back-to-Back Agreement increased $18 million in 2005 compared to the same period in 2004. Unrealized gains on the Back-to-Back Agreement decreased by $70 million for the same period.

Operations and Maintenance. *Operations and maintenance expens*es decreased by $1 million primarily due to:

- a decrease of $34 million in corporate costs allocated to the United States segment in 2005 primarily as a result of efforts to reduce corporate overhead expenses. Corporate expenses allocated were $142 million in 2005 compared to

$176 million in 2004;

- an increase of $21 million of which $8 million is related to maintenance on the dam at Swinging Bridge, $5 million is related to environmental remediation costs at the Lovett and Hillburn facilities and $9 million is due to increased maintenance at Mid-Atlantic, which includes $3 million related to the outages at the Morgantown and Chalk Point facilities. See Item 1. Business for further discussion;

- an increase of $10 million due to a reduction recorded in 2004 in the reserve related to receivables from Enron;

- an increase of $8 million related to the property tax settlements of certain California and New York generation assets in 2004; and

- a decrease of $5 million due to additional rent expense in 2004 for our Morgantown and Dickerson baseload units.

Impairment losses and restructuring charges. Impairment losses and restructuring charges increased $4 million due to an impairment charge of $9 million in 2005 related to suspended construction project costs for Wyandotte that are not included in the expected sale of those assets and other suspended construction projects. In 2004, we recognized a $3 million impairment charge. Restructuring charges were $4 million and $6 million for 2005 and 2004, respectively.

Loss (gain) on sales of assets. Loss on sales of assets, net decreased $31 million. The loss of $19 million in 2005 relates to the sale of Wyandotte. See Note 9 to our consolidated financial statements contained elsewhere in this report for a further discussion of assets held for sale. The loss on sales of assets, net of $50 million in 2004 was primarily due to a loss of $65 million related to the sale of three natural gas combustion turbines offset by a gain of $16 million related to the sale of our remaining Canadian natural gas transportation contracts and certain natural gas marketing contracts.

2004 versus 2003

The following table summarizes gross margin by region for our United States segment for the years ended December 31, 2004 and 2003 (in millions):

	Years Ended December 31,		
	2004	**2003**	**Increase/ (Decrease)**
Mirant Americas Generation			
Mid-Atlantic	$ 424	$ 352	$ 72
Northeast	249	143	106
West and eliminations	152	182	(30)
Total Mirant Americas Generation	825	677	148
Other United States generation	170	175	(5)
TPA amortization	344	426	(82)
Other, including TPAs and PPAs	(143)	(56)	(87)
Total	$ 1,196	$ 1,222	$ (26)

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Gross Margin. Gross margin decreased by $26 million primarily due to the following:

Mid-Atlantic operations gross margin increased $72 million primarily due to the termination in April 2003 of an intercompany capacity and energy agreement with our Mirant Americas Energy Marketing subsidiary. As a result of the intercompany agreement, approximately $94 million of Mid-Atlantic gross margin for the year ended December 31, 2003, is included in other gross margin. This agreement ended May 1, 2003. Excluding the impact of this agreement, Mid-Atlantic operations gross margin would have been $22 million lower in 2004 than in 2003, primarily due to the following:

- an increase of approximately $46 million driven by higher market prices for power;

- an increase of $46 million related to an increase in prices for capacity and ancillary services;

- a decrease of approximately $68 million related to net unrealized losses on derivative contracts for future periods. Of these contracts, $58 million related to power and $10 million related to oil and gas, and were entered into to economically hedge a portion of the energy price risk related to future Mid-Atlantic operations. The decrease in value of these energy derivative contracts is due to an increase in forward power prices;

- a decrease of $20 million related to a higher emissions expense due mainly to higher prices for SO2 emissions allowances;

- a decrease of $14 million related to a reduction in realized gains on economic fuel hedges; and

- a decrease of $11 million related to the termination of contracts in 2004.

Northeast operations gross margin increased $106 million primarily due to the following:

- an increase of $43 million related to net unrealized gains on derivative instruments of approximately $31 million in 2004 compared to $12 million in net unrealized losses in 2003;

- an increase of $27 million due to certain forced outages and transmission line problems in 2003 that did not recur in 2004;

- an increase of $22 million in our realized economic hedging margin due to the impact of 2003 short positions on power in a market where prices for power were rising;

- an increase of $6 million due to the sale of surplus emissions allowances; and

- an increase of $11 million due to the impact of intercompany emissions allowance sales in 2004.

West and eliminations reflect a reduction in gross margin of $19 million for our generation units in California and Texas, and a consolidation adjustment of $11 million to eliminate the impact of intercompany emissions transfers in 2004. In California, gross margin decreased by approximately $3 million primarily due to a decrease in gains on realized economic hedges of $22 million as a result of reduced economic hedging activity offset by $18 million of savings on gas reservation charges following a contract rejection. In Texas, gross margin decreased by $16 million primarily due to lower energy prices and a new tolling agreement that began in August 2004 with a third party that is at lower prices than what these units received under a prior agreement with Mirant Americas Energy Marketing.

Non-cash revenue related to the amortization of the TPAs decreased by $82 million primarily due to the expiration of one of the two TPAs in June 2004 and the impact of a late contract change in 2003. The second TPA expired in January 2005.

Other gross margin decreased by $87 million primarily resulting from $94 million of gross margin in 2003 received from the market for power at higher prices than the fixed prices paid under an intercompany capacity and energy agreement with Mirant Mid-Atlantic. As a result, approximately $94 million of Mid-Atlantic gross margin for the year ended December 31, 2003 is included in other gross margin. This

agreement ended May 1, 2003. Other gross margin also includes our realized losses under the TPAs and the realized and unrealized gains and losses under the power purchase agreements with PEPCO.

Operating Expenses. Operating expenses decreased by $3,334 million due to the following factors:

- An increase of $28 million in operations and maintenance expense primarily due to the following:

- an increase of $87 million in corporate costs allocated to the North America segment in the 2004 period. Corporate expenses allocated were $176 million for the year ended December 31, 2004, compared to $89 million for the same period in 2003. In 2004, we began allocating all corporate costs to business units while in 2003 a fixed charge methodology was used and a significant amount of corporate costs were retained at Corporate;

- an increase of approximately $13 million related to the Commodity Futures Trading Commission (CFTC) settlement in December 2004. See Note 15 to our consolidated financial statements contained elsewhere in this report;

- an increase of $7 million related to the additional rent expense for our Morgantown and Dickerson baseload units as a result of the Bankruptcy Court s granting the motion compelling Mirant Mid-Atlantic to pay incremental rent;

- a decrease of $10 million in operations and maintenance related to a reduction in the allowance related to receivables from Enron recorded in 2004;

- a decrease of $8 million related to property tax settlements in certain California and New York generation assets;

- a decrease of $32 million related to an energy marketing customer bad debt expense reflected in 2003; and

- a decrease of $29 million, of which approximately $23 million is primarily related to reduced scope and scale of our energy marketing operations. This reduction is primarily attributable to labor costs due to workforce reductions that occurred in the last quarter of 2003.

- A decrease of $35 million in depreciation and amortization expense was primarily due to lower depreciation expense related to our property, plant and equipment after our $1,338 million impairment of long-lived assets in the fourth quarter of 2003;

- A decrease of $2,067 million for goodwill impairment charges is related to the impairment of goodwill in 2003 associated with our North America operations. For further discussion, see Critical Accounting Policies and Estimates and Note 8 to our consolidated financial statements contained elsewhere in this report;

- A decrease of $1,338 million for long-lived asset impairment losses is due to an impairment recorded in 2003 for our turbines, power islands and other project costs. For further discussion, see Critical Accounting Policies and Estimates ;

- A decrease of $10 million in other impairment losses and restructuring charges is primarily due to additional cost reductions in 2003 related to costs to cancel equipment orders and service agreements along with workforce reduction and other employee termination-related charges; and

- An increase of $88 million in loss on sales of assets, net primarily relates to a loss of approximately $65 million on the planned sale of three natural gas combustion turbines, offset by a gain of $16 million related to the sale of the remaining Canadian natural gas transportation and certain natural gas marketing contracts. In 2003 the gain on sales of assets of $38 million primarily related to the sale of gas storage contracts in our Canadian trading operations.

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Philippines

Our Philippine segment consists of our ownership interest in power generating operations. The following table summarizes the operations of our Philippine business for the years ended December 31, 2005, 2004 and 2003 (in millions):

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Operating revenues:						
Generation	$ 477	$ 471	$ 6	$ 471	$ 480	$ (9)
Integrated utilities and distribution	14	16	(2)	16	25	(9)
Total operating revenues	491	487	4	487	505	(18)
Cost of fuel, electricity and other products	27	22	5	22	26	(4)
Gross margin	464	465	(1)	465	479	(14)
Operating expenses:						
Operations and maintenance	111	101	10	101	92	9
Depreciation and amortization	79	81	(2)	81	82	(1)
Goodwill impairment losses		582	(582)	582		582
Impairment losses and restructuring charges					2	(2)
(Gain) loss on sales of assets, net	(1)		(1)			
Total operating expenses	189	764	(575)	764	176	588
Operating income (loss)	$ 275	$ (299)	$ 574	$ (299)	$ 303	$ (602)

The following table summarizes capacity factor (average percentage of full capacity used over a year) and power generation volumes by operations (in gigawatt hours) for our Philippine segment for the years ended December 31, 2005, 2004 and 2003:

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Philippines capacity factor	38 %	44 %	(6)%	44 %	43 %	1 %
Philippines generation volumes	6,421	7,021	(600)	7,021	6,973	48

2005 versus 2004

Gross Margin. Our gross margin decreased by $1 million primarily due to the following:

- an increase of $6 million in generation revenue due to rate increases in our energy supply business;
- a decrease of $5 million due to an increase in fuel cost from higher commodity fuel prices for our energy supply business; and
- a decrease of $2 million in generation revenue due to the expiration of the Build Operate and Transfer project agreement for Navotas II facilities in 2005.

Our capacity factor does not significantly affect gross margin as over 90% of our generation capacity is sold under long-term energy conversion agreements with the Philippine government-owned NPC.

Operating Expenses. Our operating expenses decreased by $575 million primarily due to the following factors:

- an increase of $10 million in operation and maintenance expenses, which reflects a decrease of $5 million in corporate costs allocated to the Philippine segment in the 2005 period. Corporate

expenses allocated were $16 million in 2005 compared to $21 million in 2004. This decrease is offset by $11 million of valuation allowance on advances made to local governments in 2005 relating to the disputed tax assessments on Pagbilao and Sual power plants and $5 million in higher maintenance costs;

- a decrease of $582 million in goodwill impairment due to the impairment of the remaining goodwill related to our Philippine operations in 2004. See Note 8 to our consolidated financial statements contained elsewhere in this report for further discussion; and

- gain on sale of assets of $1 million in 2005 primarily related to assets sold to a subsidiary of MGC, a 50%-owned joint venture in the Philippines.

2004 versus 2003

Gross Margin. Our gross margin decreased $14 million primarily due to the following:

- a decrease of $7 million related to assets that were no longer owned, operated or consolidated in 2004 that were included in 2003 results;

- a decrease of $3 million due to lower nominated capacity from Pagbilao as a result of changes to our long-term energy conversion agreements; and

- a decrease of $4 million primarily driven by higher commodity fuel prices and higher energy sales delivered for our energy supply business in 2004.

Operating Expenses. Our operating expenses increased by $588 million primarily due to the following factors:

- Operations and maintenance expense increased by $9 million primarily as a result of the following:

- an increase of $12 million in corporate costs allocated to the Philippine segment in the 2004 period. Corporate expenses allocated were $21 million for the year ended December 31, 2004, compared to $9 million for the same period in 2003. In 2004, we began allocating all corporate costs to business units while in 2003 a fixed charge methodology was used and a significant amount of corporate costs were retained at Corporate;

- an increase of $9 million related to an expired and unfulfilled contract obligation provision in 2003;

- a decrease of $6 million related to assets that were no longer owned, operated, or consolidated by us in 2004 that were included in the 2003 results; and

- a decrease of $6 million due to lower insurance costs and other expenses.

- An increase of $582 million in goodwill impairment which represents the impairment of the remaining goodwill related to our Philippine operations in 2004. See Note 8 to our consolidated financial statements contained elsewhere in this report for further discussion.

- A decrease of $2 million in other impairment losses and restructuring charges were related to the severance of employees and other employee termination related charges in 2003.

Caribbean

Our Caribbean segment consists of our ownership interest in power generating operations in Curacao and Trinidad and Tobago and our ownership interest in integrated utilities in Jamaica and the Bahamas. The following table summarizes the operations of our Caribbean businesses for the years ended December 31, 2005, 2004 and 2003 (in millions):

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Operating revenues:						
Generation	$ 7	$ 6	$ 1	$ 6	$ 3	$ 3
Integrated utilities and distribution	723	557	166	557	523	34
Total operating revenues	730	563	167	563	526	37
Cost of fuel, electricity and other products	411	272	139	272	253	19
Gross margin	319	291	28	291	273	18
Operating expenses:						
Operations and maintenance	183	193	(10)	193	164	29
Depreciation and amortization	43	41	2	41	34	7
Impairment losses and restructuring charges		1	(1)	1	11	(10)
Loss (gain) on sales of assets, net		2	(2)	2	2	
Total operating expenses	226	237	(11)	237	211	26
Operating income	$ 93	$ 54	$ 39	$ 54	$ 62	$ (8)

The following table summarizes capacity factor (average percentage of full capacity used over a year) and power generation volumes by operations (in gigawatt hours) for our Caribbean segment for the years ended December 31, 2005, 2004 and 2003:

	Years Ended December 31,					
	2005	**2004**	**Increase/ (Decrease)**	**2004**	**2003**	**Increase/ (Decrease)**
Caribbean capacity factor	51 %	50 %	1 %	50 %	49 %	1 %
Caribbean generation volumes	8,501	8,250	251	8,250	8,021	229

2005 versus 2004

Gross Margin. Our gross margin increased by $28 million primarily due to an increase of $41 million related to regulatory approved rate increases in non-fuel tariffs at our Jamaica integrated utility in June 2004 and September 2005 and an increase of $3 million in our Bahamas operations related to higher sales in 2005. This was partially offset by approximately $17 million from our Jamaica integrated utility due to higher system losses related to increased theft of electricity and fuel costs that cannot be recovered through regulatory approved fuel rates, because the Jamaican utility did not fully meet its prescribed efficiency targets.

Operating Expenses. Our operating expenses decreased by $11 million primarily due to a decrease of $10 million in operation and maintenance expenses, which also reflects a decrease of $1 million in corporate costs allocated to the Caribbean segment in the 2005 period. Corporate expenses allocated were $15 million in 2005 compared to $16 million in 2004. The decrease also included $8 million related to a pension surplus.

2004 versus 2003

Gross Margin. Our gross margin increased $18 million primarily due to an increase in energy sales and regulatory approved rate increases in non-fuel tariffs at our Jamaica integrated utility in 2004.

Operating Expenses. Our operating expenses increased by $26 million primarily due to the following factors:

- Operations and maintenance expense increased by $29 million primarily as a result of the following:

- an increase of $13 million in corporate costs allocated to the Caribbean segment in the 2004 period. Corporate expenses allocated were $16 million for the year ended December 31, 2004 compared to $3 million for the same period in 2003. In 2004, we began allocating all corporate costs to business units while in 2003 a fixed charge methodology was used and a significant amount of corporate costs were retained at Corporate;

- an increase of $9 million related to hurricane damage expenses; and

- an increase of $5 million in operating and maintenance expenses associated with new vehicle leases and increased bad debt expense.

- a decrease of $10 million in other impairment losses and restructuring charges related to the severance of employees and other employee termination related charges in 2003; and

- an increase of $7 million in depreciation and amortization due to completed construction projects in 2004.

Corporate

The following table summarizes our corporate expenses for the years ended December 31, 2005, 2004 and 2003 (in millions):

	Years Ended December 31,					
	2005	2004	Increase/ (Decrease)	2004	2003	Increase/ (Decrease)
Operating (credits) expenses:						
Total corporate costs	$ 171	$ 229	$ (58)	$ 229	$ 269	$ (40)
Less: allocated costs	175	214	(39)	214	101	113
	(4)	15	(19)	15	168	(153)
Operations and maintenance	(32)	(20)	(12)	(20)	128	(148)
Depreciation and amortization	18	21	(3)	21	24	(3)
Long-lived asset impairment losses					1	(1)
Other impairment losses and restructuring charges	10	13	(3)	13	25	(12)
Gain on sales of assets, net		1	(1)	1	(10)	11
Total operating (credits) expenses	$ (4)	$ 15	$ (19)	$ 15	$ 168	$ (153)

We used budgeted costs to determine cost allocations to the operating segments. This creates a timing difference that is resolved through adjustments to the cost allocation amount in the following month. In addition, cost allocations are reflected in operations and maintenance expense, regardless of the statement of operations classification of the expense incurred by the corporate segment. As a result, depreciation and amortization and other expense items are reflected as reductions of operations and maintenance expense when allocated. This contributes to the negative operations and maintenance expense for the corporate segment but has no impact on the consolidated statements of operations.

2005 versus 2004

The corporate operating credits for the year ended December 31, 2005, represent the amount of billings to operating segments in excess of costs incurred during this period. The corporate operating expenses for the year ended December 31, 2004, represent the amount of costs incurred in excess of billings to operating segments during this period. Before allocations to operating segments, our corporate expenses in total are $58 million lower in 2005 compared to 2004. This decrease is primarily due to cost cutting efforts and reflects lower insurance expense, consulting fees and salaries and wages. Allocated expenses are $39 million lower in 2005 compared to 2004.

2004 versus 2003

The corporate operating expenses for the year ended December 31, 2004, represent the amount of costs incurred in excess of billings to operating segments during this period. Before allocations to operating segments, our corporate expenses in total were $40 million lower in 2004 compared to 2003. This 15% decrease was primarily due to a headcount reduction of approximately 10% as a result of a workforce reduction program in October 2003. Allocated expenses were $113 million higher in 2004 compared to 2003. This increase was due to the change in allocation methodology discussed below.

In 2003, certain corporate costs were not allocated to a reporting segment. Beginning January 1, 2004, we changed our allocation methodology related to corporate overhead expenses to better reflect our operating structure. As a result, substantially all of our corporate operating expenses are now allocated to our United States, Philippines and Caribbean segments. The new methodology allocates costs using several methods but is primarily based on gross margin, property, plant and equipment balances, and labor costs.

Other Significant Consolidated Statements of Operations Comparisons

The following table summarizes our consolidated other income and expenses for the years ended December 31, 2005, 2004 and 2003 (in millions):

	Years Ended December 31,					
	2005	2004	Increase/ (Decrease)	2004	2003	Increase/ (Decrease)
Other (expense) income, net:						
Interest expense	$ (1,511)	$ (130)	$ (1,381)	$ (130)	$ (379)	$ 249
Interest rate hedging losses					(110)	110
Gain on sales of investments, net	45		45		67	(67)
Equity in income of affiliates	33	26	7	26	33	(7)
Impairment losses on minority owned affiliates	(23)		(23)			
Interest income	31	11	20	11	24	(13)
Other, net	(59)	68	(127)	68	48	20
Total other (expense), net	$ (1,484)	$ (25)	$ (1,459)	$ (25)	$ (317)	$ 292
Reorganization items, net	$ 72	$ 259	$ (187)	$ 259	$ 290	$ (31)
Provision for income taxes	123	87	36	87	126	(39)
Minority interest	23	21	2	21	35	(14)
Loss from discontinued operations, net	(7)	(70)	63	(70)	(173)	103
Cumulative effect of changes in accounting principles, net	(16)		(16)		(29)	29

2005 versus 2004

Interest Expense. Interest expense increased by $1.4 billion 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. See Note 3 to our consolidated financial statements contained elsewhere in this report for further discussion.

Gain on sales of investments, net. Gain on sale of investments, net includes a $44 million gain related to the 2005 sale of a portion of our investment in a company that provides an electronic commerce platform for the purchase and sale of energy commodities. See Note 10 to our consolidated financial statements contained elsewhere in this report for further discussion.

Impairment losses on minority owned affiliates. As a result of uncertainty related to the timing and resolution of contract and rate approvals, in 2005 we recorded an impairment of $23 million related to MGC, a joint venture in the Philippines. See Note 10 to our consolidated financial statements contained elsewhere in this report for further discussion.

Interest income. Interest income increased by $20 million due to higher interest rates and higher cash balances in our Philippines operations.

Other, net. Other, net decreased by $127 million due to a loss of $83 million from higher foreign currency losses in 2005 primarily related to our European entities being legally liquidated in the fourth quarter of 2005. This liquidation resulted in the write-off of previously reported currency translation adjustments for the entities. We also had a gain of $37 million in 2004 related to the extinguishment of $83 million of our 2.5% convertible debentures due 2021 that were included in liabilities subject to compromise.

Reorganization items, net. Reorganization items, net represents 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 includes:
- $283 million gain on the Plan;
- $196 million loss related to changes in estimated claims;
- $32 million gain related to the California Settlement;
- $226 million in professional and administrative fees; and
- $35 million of interest income and other gains, net.
- For the year ended December 31, 2004, this amount includes:
- $171 million loss related to estimated damage claims on rejected and amended contracts;
- $110 million in professional and administrative fees; and
- $22 million of interest income and other gains, net.

Provision for Income Taxes. The Provision for income taxes increased by $36 million for the year ended December 31, 2005, compared to 2004 primarily due to:

- a $19 million increase in 2005 tax expense related to a change in tax rates for several of our foreign subsidiaries;
- a net increase compared to 2004 for state and foreign tax contingencies in the amount of $37 million;

- a decrease of $19 million in 2005 due to a favorable settlement of foreign taxes including a settlement pursuant to which Mirant has agreed to forgo net operating loss carryforwards in the Netherlands, which had no book value in our consolidated financial statements;

- an increase of $12 million in 2005 as a result of additional income generated from our Caribbean operations;

- a net increase of $10 million due to adjustments of the tax receivable from the Southern Company relating to audit periods when Mirant was a subsidiary of the Southern Company; and

- a decrease of $23 million due to an adjustment in the deferred tax balances of several foreign subsidiaries.

We currently record a tax provision for all income taxes as appropriate but record no tax benefit for losses for federal and state income tax purposes in the United States. We provide a valuation allowance, where appropriate, for federal, state and foreign income tax purposes. See Critical Accounting Policies and Estimates contained elsewhere in this report for further discussion.

Discontinued Operations. The $7 million and $70 million losses from discontinued operations for the years ended December 31, 2005 and 2004, respectively, include the sale of Wichita Falls and the disposal of the Coyote Springs 2 and Wrightsville facilities and certain suspended construction projects. The loss in 2004 is primarily related to an impairment charge of $48 million at the Coyote Springs 2 facility. Amounts relating to the sale of Wichita Falls have been reclassified to be reflected in this category. See Note 9 to our consolidated financial statements contained elsewhere in this report for further discussion.

Cumulative Effect of Changes in Accounting Principles. In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations,* (FIN 47). The interpretation requires companies to recognize a liability for the fair value of a legal obligation to perform asset retirement activities that are conditional on a future event if the amount can be reasonably estimated. FIN 47 is effective for fiscal years ending after December 15, 2005. We adopted the provisions of FIN 47 in the fourth quarter of 2005. The impact of FIN 47 resulted in a cumulative effect adjustment of $16 million in the consolidated statements of operations.

2004 versus 2003

Interest expense. Interest expense decreased by $249 million due to the Chapter 11 filings. The accrual of interest expense associated with the debt of the Mirant Debtors, with the exception of West Georgia, was suspended. Therefore, subsequent to the Petition Date, no interest expense related to those obligations was recorded. Contractual interest on liabilities subject to compromise in excess of reported interest was approximately $535 million and $239 million for the years ended December 31, 2004 and 2003, respectively.

Interest rate hedging losses. Interest rate hedging losses of $110 million in 2003 represents the reclassification of interest rate hedging losses from other comprehensive income to interest expense. The reclassification resulted primarily from the suspension of interest payments on the debt associated with the interest rate swaps, pursuant to the Chapter 11 filings.

*Gain on sales of investments, net. G*ain on sale investments, net includes a $67 million gain related to the 2003 sale of our 50%-owned investment in Birchwood Power Partners, LP.

Other, net. In 2004, other, net includes 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. During 2003, we recorded income of $11 million related to the sale of certain energy marketing contracts.

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Reorganization items, net. Reorganization items, net represents expense or income amounts that were recorded in the financial statements as a result of the bankruptcy proceedings.

- For the year ended December 31, 2004, this amount includes:
- $171 loss million related to estimated damage claims on rejected and amended contracts;
- $110 million in professional and administrative fees; and
- $22 million of interest income and other gains, net.
- For the year ended December 31, 2003, this amount includes:
- $241 million loss related to estimated damage claims on rejected and amended contracts;
- $48 million in professional and administrative fees; and
- $1 million of interest expense, net.

Provision for Income Taxes. The consolidated statements of operations for the year ended December 31, 2004, reflect an income tax provision of $87 million. We provide a valuation allowance, where appropriate, for federal, state and foreign income tax purposes. See Critical Accounting Policies and Estimates contained elsewhere in this report for further discussion.

Discontinued Operations. The $70 million loss from discontinued operations for the year ended December 31, 2004, includes Coyote Springs and Wrightsville that were disposed of in 2005. The $173 million loss from discontinued operations for the year ended December 31, 2003, reflects the generating facilities that were disposed of in 2003. Amounts relating to the sale of Wichita Falls have been reclassified to be reflected in this category. See Note 9 to our consolidated financial statements contained elsewhere in this report for further discussion.

Cumulative Effect of Changes in Accounting Principles. As a result of the consensus on the Emerging Issues Task Force (EITF) Issue 02-03, all non-derivative energy trading contracts as of January 1, 2003, that existed on October 25, 2002, have been adjusted to historical cost resulting in a cumulative effect adjustment of $26 million, after tax, which was recorded in the first quarter of 2003. Certain of these contracts were reclassified from price risk management liabilities to transition power agreements and other obligations on our consolidated balance sheets. We also adopted SFAS No. 143 *Accounting for Asset Retirement Obligations* (SFAS No. 143) effective January 1, 2003, and recognized an after-tax charge of $3 million associated with its implementation.

Financial Condition

Liquidity and Capital Resources

During the pendency of the Chapter 11 proceedings we satisfied our liquidity and capital requirements with cash from operations and a $500 million debtor-in-possession credit facility that was approved by the Bankruptcy Court and which provided for borrowings or the issuance of letters of credit. The Chapter 11 proceedings resulted in various restrictions on our activities, including limitations on financing, and the implementation of a centralized cash management system that provided for the collection, concentration and disbursement of funds. The Chapter 11 proceedings also caused uncertainty in our relationships with vendors, suppliers, customers and others with whom we conducted or sought to conduct business. During the Chapter 11 proceedings, we typically posted cash collateral with counterparties. Going forward, we expect relationships with vendors, suppliers, customers, counterparties and others to return to normal industry practices, including the posting of letters of credit instead of cash collateral.

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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 276.5 million shares of our new common stock were distributed to holders of unsecured claims and equity securities. New Mirant also issued two series of warrants, expiring January 3, 2011, that entitle the holders to purchase an aggregate of approximately 53 million shares of common stock. In addition, 23.5 million shares of common stock were reserved for unresolved claims. Approximately 19 million shares were reserved for the omnibus incentive plan for employees and directors. Our authorized capital stock consists of 1.5 billion shares of Mirant common stock and 100 million shares of preferred stock. As part of the Plan, we eliminated approximately $5.9 billion of debt and approximately $2.6 billion of additional claims and disputes through our distribution or planned distribution of new common stock and $1,948 million in cash among our creditors.

On December 23, 2005, our subsidiary Mirant North America issued a note offering for $850 million of 7.375% senior unsecured notes due 2013. The funds from this issuance were initially placed in escrow and were released from escrow on January 3, 2006, upon consummation of the Plan. On January 3, 2006, Mirant North America entered into an $800 million senior secured revolving credit facility and a $700 million senior secured term loan. In connection with the closing, $200 million of drawings under the senior secured term loan were deposited into a cash collateral account to support the issuance of up to $200 million of letters of credit issued under the senior secured term loan.

As of March 3, 2006, we have approximately $42 million recorded for unresolved claims liabilities that we expect to settle in cash.

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; and (iii) $200 million of letters of credit capacity under Mirant North America s $700 million term loan.

Our operating cash flows may be impacted by, among other things: (i) the difference between the cost of a specific fuel used to generate one megawatt hour of electricity and the market value of the electricity generated (conversion spread); (ii) commodity prices (including prices for natural gas, coal, oil and electricity); (iii) the cost of ordinary course operations and maintenance expenses; (iv) planned and unplanned outages; (v) contraction of terms by trade creditors; and (vi) 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 these ratio tests in the future could be impaired by factors which negatively affect the performance of its power generation facilities, including interruptions in operation such as the recent temporary shutdown and continuing curtailment of operations of the Potomac River generation facility.

A significant portion of cash from our Philippine operations is generated by the power generation facilities at Mirant Sual Corporation (Mirant Sual) and Mirant Pagbilao Corporation (Mirant Pagbilao). Under debt agreements for these subsidiaries, Mirant Sual and Mirant Pagbilao are subject to covenants that restrict their right to make distributions to Mirant. Under the financing agreements for the Sual project, Mirant Sual is restricted from paying dividends and making other subordinated loan payments, if any, if it does not comply with the required debt service coverage ratio. Primarily because of the expiration of its income tax holiday in October 2005, Mirant Sual is not expected to comply with the required debt service coverage ratio in 2006. It expects to be able to meet the debt service coverage ratio in 2007. As a result, Mirant Sual s cash will not be available to us for use in 2006. As of December 31, 2005, Mirant Sual had a cash balance of approximately $81 million.

United States

Mirant Americas Generation

As part of the Plan, our subsidiary Mirant Americas Generation, reinstated senior notes of $1.7 billion maturing in 2011, 2021 and 2031 and paid $452 million of accrued interest.

Interest Rate; Maturity Date; Redemption Rights. The notes, which mature on May 1, 2011, October 1, 2021, and May 1, 2031, were issued in aggregate principal amounts of $850 million, $450 million and $400 million and bear interest at 8.3%, 8.50%, and 9.125%, respectively. Interest on the 2021 notes is payable on each April 1 and October 1 and interest on the 2011 notes and 2031 notes is payable on each May 1 and November 1.

At any time and at its option, Mirant Americas Generation may redeem the notes of each series, in whole or in part (if in part, by lot or by such other method as the trustee shall deem fair or appropriate) at the redemption price of 100% of principal amount of such notes, plus accrued interest on the principal amount of such notes, if any, to the redemption date, plus the make-whole premium for such notes. The make-whole premium is calculated as follows: (i) the average life of the remaining scheduled payments of principal in respect of outstanding notes of such series (the Remaining Average Life of the notes of such series) as of the redemption date; (ii) the yield to maturity for the United States treasury security having an average life equal to the Remaining Average Life of the notes of such series and trading in the secondary market at the price closest to the principal amount thereof (the Primary Issue for the notes of such series) (subject to extrapolation if no United States treasury security has an average life equal to the Remaining Average Life of the notes of such series); and (iii) the discounted present value of the then-remaining scheduled payments of principal and interest (but excluding that portion of any scheduled payment of interest that is actually due and paid on the redemption date) in respect of outstanding notes of such series as of the redemption date using a discount factor equal to the sum of (x) the yield to maturity for the Primary Issue for the notes of such series, plus (y) 25 basis points for the 2011 notes, 37.5 basis points for the 2021 notes, and 37.5 basis points for the 2031 notes. The amount of make-whole premium in respect of notes to be redeemed shall be an amount equal to (x) the discounted present value of such notes to be redeemed determined in accordance with clause (iii) above, minus (y) the unpaid principal amount of such new notes; provided, however, that the make-whole premium shall not be less than zero.

Ranking. The notes are senior unsecured obligations of Mirant Americas Generation, and are not secured by any affiliates or subsidiaries of Mirant Americas Generation. Thus, the notes are structurally subordinated to all existing and future liabilities of Mirant North America and its subsidiaries, including the indebtedness described below under Mirant North America and the obligations under the Mirant Mid-Atlantic leveraged leases described below under Mirant Mid-Atlantic Operating Leases.

Certain covenants. The notes are issued under an indenture that limits the ability of Mirant Americas Generation to:

- incur, assume or guarantee additional indebtedness, or permit its subsidiaries to incur, assume or guarantee indebtedness;
- create liens;
- sell assets; and
- merge, consolidate or sell or otherwise dispose of all or substantially all of our assets.

These covenants are subject to a number of important exceptions and qualifications.

Mirant North America

As contemplated by the Plan, our subsidiary Mirant North America, entered into senior secured credit facilities (the senior secured credit facilities) with a syndicate of banks, financial institutions and other entities, including JPMorgan Chase Bank, N.A., Deutsche Bank Trust Company Americas and Goldman Sachs Credit Partners L.P., as lenders (the Lenders), and, together with Mirant North America Finance Corp., a subsidiary of Mirant North America, has issued $850 million aggregate principal amount of 7.375% senior unsecured notes due 2013 (the notes).

Senior Secured Credit Facilities

The Mirant North America senior secured credit facilities 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 the issuance of letters of credit. The senior secured term loan was made in a single drawing at closing and will amortize in nominal 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 connection with the closing, $200 million of drawings under the senior secured term loan were deposited into a cash collateral account to support the issuance of up to $200 million of letters of credit issued under the senior secured term loan.

Interest rates. Loans under the senior secured credit facilities are available at either of the following rates: (i) a fluctuating rate of interest per annum equal to on any given day the greater of (a) the interest rate per annum publicly announced by JPMorgan Chase Bank, N.A. as its prime rate in effect at its principal office in New York City on that day, and (b) the federal funds rate in effect on that day plus 0.50%, plus the applicable margin described below (base rate), or (ii) a fixed rate determined for certain interest periods selected equal to U.S. dollar London InterBank Offered Rate (LIBOR) plus the applicable margin described below (Eurodollar rate).

The applicable margin with respect to loans under the senior secured revolving credit facility is 1.25% in the case of base rate loans, or 2.25% in the case of Eurodollar rate loans. The applicable margin will also be subject to a possible reduction of up to 0.50% based on the achievement and maintenance of certain leverage ratios by Mirant North America. The applicable margin with respect to the senior secured term loan is 0.75% in the case of base rate loans, or 1.75% in the case of Eurodollar rate loans.

Guarantees; Ranking and security. The obligations of Mirant North America under the senior secured credit facilities are unconditionally and irrevocably guaranteed by all of its direct and indirect subsidiaries, except (i) Mirant Energy Trading and Mirant Mid-Atlantic and its subsidiaries, (ii) until such time such entities emerge from Chapter 11 proceedings, Mirant New York, Mirant Bowline, Mirant Lovett, Mirant NY-Gen and Hudson Valley Gas Corporation, and (iii) any of subsidiaries designated as unrestricted subsidiaries from time to time ((ii) and (iii) together, the unrestricted subsidiaries). The guarantee obligations of these subsidiary guarantors are secured by first priority security interests on

substantially all the assets of such subsidiary guarantors, subject to certain permitted liens and certain exceptions.

All loans under the senior secured credit facilities are senior, secured indebtedness of Mirant North America secured by first priority security interests in substantially all of the assets of Mirant North America subject to permitted liens under the senior secured credit facilities and certain exceptions. The obligations of the subsidiaries of Mirant North America that are providing guarantees under the senior secured credit facilities are secured by first priority security interests in substantially all of the assets of each such subsidiary, subject to certain permitted liens under the senior secured credit facilities and certain exceptions.

Commitment/facility fees and default interest. A commitment fee calculated on the daily average unused portion of the commitments under the senior secured revolving credit facility is payable quarterly in arrears at an annual rate of 0.375%. The commitment fee is subject to a possible reduction of 0.125% based on the achievement and maintenance of certain leverage ratios by Mirant North America.

A fee on outstanding letters of credit under the senior secured revolving credit facility is paid to the Lenders quarterly in arrears on a pro rata basis. The letter of credit fee is calculated on the average daily aggregate available amount under all letters of credit under the senior secured revolving credit facility at a rate per annum equal to the applicable margin for Eurodollar rate loans under the senior secured revolving credit facility less the amount of the fronting fee of the issuing banks under the senior secured revolving credit facility. A fronting fee at the rate of 0.125% per annum calculated on the face amount of each letter of credit under the senior secured revolving credit facility and each letter of credit that is cash collateralized with a portion of the senior secured term loan proceeds will be paid quarterly in arrears to the relevant issuing bank.

In the event of a default in the payment of principal or interest under the senior secured credit facilities or in the payment of any fees or other amounts due and payable under the related loan documents, interest accrues on the overdue amount at the applicable rate plus an additional 2% until such amount is paid in full.

Certain covenants. The senior secured credit facilities contain covenants that:

- require Mirant North America to maintain at the end of each fiscal quarter: (i) a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 2:1, and (ii) a ratio of net debt to EBITDA of not more than 6:1, in each case calculated on a rolling four fiscal quarter basis ending on the last day of such fiscal quarter;

- restrict the ability of Mirant North America and its restricted subsidiaries to incur debt other than certain permitted debt unless, the ratio of net debt to EBITDA is less than 4:1, calculated on a rolling four fiscal quarter basis ending on the last day of such fiscal quarter and after giving pro forma effect to the incurrence of the debt; and

- restrict the ability of Mirant North America and its restricted subsidiaries to make certain restricted payments, including, without limitation, (i) any dividend payments or distribution of cash or property, (ii) payments, redemption or repurchase of affiliate subordinated debt or (iii) purchase or redemption of its or its restricted subsidiaries capital stock subject to certain exceptions, including the ability to make payments to Mirant Americas Generation to be applied to interest payments due on Mirant Americas Generation senior notes maturing in 2011, 2021 and 2031, as long as there is no default or event of default and none would result there from.

In addition, the senior secured credit facilities contain customary covenants that restrict the ability of Mirant North America and its restricted subsidiaries to:

- engage in mergers, acquisitions and asset sales;

- incur liens and engage in sale-leaseback transactions;
- make investments and capital expenditures;
- transact with affiliates; and
- change its fiscal year.

Events of default. The senior secured credit facilities contain customary events of default, including, without limitation, payment defaults, material breach of representations and warranties, covenant defaults, cross-defaults, cross-accelerations, material judgments and certain events of bankruptcy or insolvency. In addition, the senior secured credit facilities contain the following events of default:

- Except with the written consent of a majority of the Lenders, the series A and B preferred shares issued by Mirant Americas should cease to be enforceable or rights of the holders thereof are amended or waived; and
- Mirant North America should cease to be controlled, directly or indirectly, by Mirant Corporation.

If an event of default occurs, the Lenders are entitled to accelerate the amounts owing under the senior secured credit facilities and to take all other actions permitted to be taken by a secured creditor.

Mandatory prepayments. Mirant North America is required to prepay the amounts outstanding under the senior secured term loan and to permanently reduce the commitments under the senior secured revolving credit facility with proceeds received from certain transactions, as follows:

- 100% of any net cash proceeds in excess of $50 million received from any asset sale that is not committed within 365 days thereof to acquire or repair assets useful in the business or is not so applied within 180 days thereafter; and
- 100% of any net cash proceeds from any insurance or other recovery payment in excess of $20 million received that is not committed within 365 days of the recovery event to acquire or repair assets useful in the business or is not so applied within 24 months thereafter.

In addition Mirant North America is further required to prepay the senior secured term loan with 50% of free cash flow (less amounts paid to Mirant Americas Generation for the purpose of paying interest on the Mirant Americas Generation senior notes) for each fiscal year (commencing with the 2006 fiscal year), provided that the foregoing percentage shall be reduced to 25% based on the achievement and maintenance of a ratio of net debt to EBITDA of 2:1 or lower.

Senior Notes

The notes were issued by Mirant North America Escrow, LLC (Mirant North America Escrow) and its wholly-owned subsidiary, Mirant North America Finance Corp. Mirant North America Escrow was a wholly-owned subsidiary of Mirant North America. Upon emergence, Mirant North America Escrow was merged with and into Mirant North America with Mirant North America as the surviving entity. Upon the consummation of the merger, Mirant North America assumed all of the obligations of Mirant North America Escrow and Mirant North America Finance Corp. became a direct, wholly-owned subsidiary of Mirant North America. Mirant North America Finance Corp. was formed and exists solely for the purpose of serving as a co-issuer of the notes and as a guarantor of the senior secured credit facilities.

Interest Rate; Maturity Date; Redemption Rights. The notes, which were issued in an aggregate principal amount of $850 million and bear interest at 7.375%, mature on December 31, 2013. Interest on the notes is payable on each June 30 and December 31, commencing June 30, 2006.

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.

Guarantees and ranking. The notes are guaranteed on a senior unsecured basis by certain subsidiaries of Mirant North America, each of which also guarantees the obligations under the senior secured credit facilities. Any subsidiaries that in the future guarantee any of the indebtedness of Mirant North America, including indebtedness under its senior secured credit facilities, or indebtedness of any subsidiary guarantor, will also guarantee the notes. The notes are:

- general unsecured obligations of Mirant North America and the subsidiary guarantors;
- effectively junior in right of payment to the secured debt of Mirant North America and the subsidiary guarantors to the extent of the value of the assets securing such debt;
- rank equally in right of payment with all of the existing and future unsecured unsubordinated debt of Mirant North America and the subsidiary guarantors;
- senior in right of payment to all of the existing and future senior subordinated and subordinated debt of Mirant North America and the subsidiary guarantors;
- structurally subordinated to all of the existing and future liabilities (including trade payables) of each of our subsidiaries that do not guarantee the notes; and
- structurally senior to all of the existing and future liabilities (including trade payables) of Mirant Corporation and Mirant Americas Generation to the extent of the value of the Mirant North America and its subsidiaries, including Mirant Mid-Atlantic.

Certain covenants. The notes are issued under an indenture with Law Debenture Trust Company of New York, as trustee (the Trustee). The indenture limits the ability of Mirant North America and its restricted subsidiaries to:

- incur, assume or guarantee additional indebtedness;
- issue redeemable stock and preferred stock;
- repurchase capital stock;
- make other restricted payments including, without limitation, paying dividends and making investments;
- create liens;
- redeem debt that is junior in right of payment to the notes;

- sell or otherwise dispose of assets, including capital stock of subsidiaries;
- enter into agreements that restrict dividends from subsidiaries;
- merge, consolidate or sell or otherwise dispose of all or substantially all of our assets;
- enter into transactions with affiliates;
- guarantee indebtedness;
- enter into sale/leaseback transactions; and
- enter into new lines of business.

These covenants are subject to a number of important exceptions and qualifications and certain covenants may be suspended in the event Mirant North America achieves and maintains an investment grade credit rating.

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. The Company is accounting for these leases as operating leases. Rent expenses associated with the Morgantown and Dickerson operating leases totaled approximately $99 million, $103 million and $96 million for the years ended December 31, 2005, 2004 and 2003, respectively. While there is variability in the scheduled payment amounts over the lease term, the Company recognizes rental expense for these leases on a straight-line basis. The rental expense based on the original scheduled rent payments is $96 million per year. The additional expense recorded in 2004 and 2005 was payable under the terms of the leases and was commensurate with the 0.5% increase in interest on the lessor notes that was payable by the lessors for the period in which Mirant Mid-Atlantic was not a reporting entity under the Exchange Act. As of December 31, 2005 and 2004, Mirant Mid-Atlantic had paid approximately $292 million and $285 million, respectively, of actual operating lease payments in accordance with the lease agreements in excess of rent expense recognized. A further $12 million of scheduled rent due on June 30, 2005, was funded through a draw made by the lease trustee on letters of credit arranged by the Company. In addition to the regularly scheduled rent payments, Mirant Mid-Atlantic paid an additional $11 million as of December 31, 2004, as required by the lease agreements. In September 2005, the lease trustees made an additional draw of $49 million prior to the expiration of the letters of credit in September 2005. This amount is recorded in funds on deposit in the consolidated balance sheets. On January 3, 2006, as part of the settlement and emergence, Mirant North America posted a $75 million letter of credit for the benefit of Mirant Mid-Atlantic to cover the debt service reserve obligation on the leases. Upon posting of the letter of credit, the Trustee returned $56 million of cash collateral held to Mirant Mid-Atlantic.

As of December 31, 2005, the total notional minimum lease payments for the remaining term of the leases aggregated approximately $2.4 billion and the aggregate termination value for the leases was approximately $1.4 billion and generally decreases over time. Mirant Mid-Atlantic leases the Morgantown and the Dickerson baseload units from third party owner lessors that purchased the baseload units from PEPCO. These owner lessors each own the undivided interests in the baseload generating facilities. The subsidiaries of the institutional investors who hold the membership interests in the owner lessors are called owner participants. Equity funding by the owner participants plus transaction expenses paid by the owner participants totaled $299 million. The issuance and sale of pass through certificates raised the remaining $1.2 billion needed for the owner lessors to acquire the undivided interests.

The pass through certificates are not direct obligations of Mirant Mid-Atlantic. Each pass through certificate represents a fractional undivided interest in one of three pass through trusts formed pursuant to three separate pass through trust agreements between Mirant Mid-Atlantic and State Street Bank and Trust Company of Connecticut, National Association, as pass through trustee. The property of the pass through trusts consists of lessor notes. The lessor notes issued by an owner lessor are secured by that owner lessor s undivided interest in the lease facilities and its rights under the related lease and other financing documents.

Certain covenants

The operative documents relating to the Mirant Mid-Atlantic leveraged leases contain certain restrictive covenants, including the following:

Limitations on restricted payments. Mirant Mid-Atlantic cannot make any of the following restricted payments (subject to certain narrow, specifically identified exceptions):

- distributions in respect of equity interests in Mirant Mid-Atlantic (in cash, property, securities or obligations other than additional equity interests of the same type);

- payments or distributions on account of payments of interest, the setting apart of money for a sinking or analogous fund for, or the purchase or redemption, retirement or other acquisition of any portion of any equity interest in Mirant Mid-Atlantic or of any warrants, options or other rights to acquire any such equity interest (or make payments to any person such as phantom stock payments, where the amount of the payment is calculated with reference to fair market or equity value of Mirant Mid-Atlantic); or

- payments on or with respect to the purchase, redemption, defeasance or other acquisition or retirement for value of any subordinated indebtedness;

unless, at the time of and after giving effect to the restricted payment, no significant lease default or lease event of default has occurred and is continuing and Mirant Mid-Atlantic: (1) can satisfy a fixed charge coverage ratio on a historical basis for the last period of four full fiscal quarters; and (2) is projected to satisfy a fixed charge coverage ratio for the next two periods of four fiscal quarters.

Mirant Mid-Atlantic assumed the leveraged leases pursuant to, and in accordance with, the treatment of such leases in the Plan. With respect to the assumption of the leveraged leases, the Plan provisions included: (i) Mirant Mid-Atlantic agreed not to issue additional lessor notes unless rated BBB /Baa3 or it has a fixed charge coverage ratio of at least 2.5:1 and the owner lessors consent; (ii) the contribution of Mirant Peaker and Mirant Potomac River to Mirant Chalk Point; (iii) the Mirant Americas Series A Preferred Shares will be issued to Mirant Mid-Atlantic; and (iv) Mirant Mid-Atlantic has made certain payments to the parties to the leveraged leases, including $6.5 million to the holders of the pass through trust certificates, $6.5 million to the owner lessors, $2.9 million as restoration payments under the leases, and approximately $22 million of professional fees of the lease parties. The $6.5 million paid to the Indenture Trustee for the benefit of the holders of the pass through certificates was paid in January 2006. The other payments were paid in December 2005.

In addition, the Plan provided that certain interpretations of, and amendments to, the Mirant Mid-Atlantic leveraged lease documentation are binding upon the parties to the leveraged leases. The interpretations and amendments, which are focused primarily on the calculation of the fixed charge coverage ratio for purposes of the restricted payments test, clarify (i) under which circumstances Mirant Mid-Atlantic may eliminate from the calculation of the fixed charge coverage ratio capital expenditures made, or projected to be made, with respect to the leased facilities, (ii) that Mirant Mid-Atlantic may, in calculating the coverage ratio for the periods prior to emergence from Chapter 11, treat capital expenditures financed with cash previously generated and retained during an earlier period as being made in such earlier period and, thus, eliminated in the calculation for the period being measured, (iii) that Mirant Mid-Atlantic may eliminate from the calculation of the fixed charge coverage ratio capital expenditures made, or projected to be made, with the proceeds of the Mirant Americas Series A Preferred Shares and similar arrangements, subject to certain conditions, and (iv) that, in determining Consolidated EBITDA (as defined in the leveraged lease documentation), all adjustments to reconcile net income to net cash provided by (used in) operating activities, excluding changes in operating assets and liabilities, as disclosed in (or projected to be included in) the cash flow statement of Mirant Mid-Atlantic are to be excluded. As of December 31, 2005, and incorporating the interpretations and amendments referred to above, Mirant Mid-Atlantic would have met the restricted payments test.

Limitation in incurrence of indebtedness. Neither Mirant Mid-Atlantic nor any of its subsidiaries (other than Mirant Potomac River and Mirant Chalk Point, each of which are defined as a Designated Subsidiary) may incur or assume any indebtedness other than Permitted Indebtedness, nor may Mirant Mid-Atlantic permit any Designated Subsidiary to incur or assume any debt other than Designated Subsidiary Permitted Indebtedness. Based on those prohibitions, generally, (1) the only indebtedness Mirant Mid-Atlantic and its subsidiaries (other than the Designated Subsidiaries) may incur is as follows:

- any indebtedness, if, after taking into account the incurrence of such indebtedness, both S&P and Moody s confirm their respective ratings of the pass through certificates outstanding prior to incurring the indebtedness, and there is no event of default outstanding under the leases;

- indebtedness incurred for working capital purposes;

- indebtedness relating to letters of credit, surety bonds or performance bonds or guarantees issued in the ordinary course of business;

- indebtedness meeting the definition of Subordinated Indebtedness ;

- indebtedness not to exceed $100 million in the aggregate for principal, less the aggregate principal amount of indebtedness incurred as set forth in operative documents;

- indebtedness represented by Interest Rate Hedging Transactions entered into in the ordinary course of business;

- indebtedness secured by a pre-existing lien on any assets acquired by Mirant Mid-Atlantic, so long as the indebtedness is recourse only to those assets and not to the general credit of Mirant Mid-Atlantic;

- with regard to subsidiaries other than the Designated Subsidiaries, the indebtedness is Non-Recourse Indebtedness (as defined in the operative documents);

- any intercompany loans;

- indebtedness incurred to finance capital expenditures made to comply with law or to finance Required Improvements as defined in the Facility Lease Agreements;

- indebtedness incurred to refinance permitted existing indebtedness, provided that period of repayment is not shorter than the original debt and the principal of the new debt does not exceed the refinanced debt except for a reasonable premium as the cost of the refinancing; or

- indebtedness guaranteed by Mirant or one or more direct or indirect parents of Mirant Mid-Atlantic, provided that each of such guarantors has a sufficiently high credit rating as set forth in the operative documents;

and (2) the only indebtedness that the Designated Subsidiaries may incur is essentially the same types of indebtedness as Mirant Mid-Atlantic is permitted to incur except that the tests are applied with regard to the applicable Designated Subsidiary, and that each Designated Subsidiary is limited by a sub-cap of $50 million in connection with the overall permission given to Mirant Mid-Atlantic and its subsidiaries to incur

$100 million of debt in the aggregate, and the Designated Subsidiaries do not have a separate category of Designated Subsidiary Permitted Indebtedness for working capital purposes, for Subordinated Indebtedness, or indebtedness represented by Interest Rate Hedging Transactions, for indebtedness incurred to refinance permitted existing indebtedness, nor for indebtedness guaranteed by Mirant or one or more direct or indirect parents of Mirant Mid-Atlantic.

Limitation on merger and consolidation or sale of substantially all assets. Mirant Mid-Atlantic is not permitted to, nor may it permit the Designated Subsidiaries to, consolidate or merge with or into any other entity, or sell, lease or otherwise dispose of all or substantially all of its properties or assets to any person or entity except that, if, after giving effect thereto, no lease event of default occurs, (a) any Designated Subsidiary may merge into Mirant Mid-Atlantic or into any other Designated Subsidiary, and (b) Mirant Mid-Atlantic or any Designated Subsidiary may merge into another entity or may sell its assets to another entity if the surviving entity (if it is an entity other than Mirant Mid-Atlantic or a Designated Subsidiary) meets certain criteria and expressly assumes all of the obligations of Mirant Mid-Atlantic or the applicable Designated Subsidiary, as the case may be, under the applicable documents.

Limitations on sale of assets. Mirant Mid-Atlantic is not permitted to, nor may it permit any Designated Subsidiary to, sell any assets other than those that fall within the definition of Permitted Asset Sales set forth in the operative documents.

Restrictions on liens. Mirant Mid-Atlantic is not permitted to, nor may it permit any Designated Subsidiary to, create, incur, assume or otherwise suffer to exist any liens on its respective assets, other than those that fall within the definition of Permitted Encumbrances set forth in the operative documents.

Assignment and sublease. Without the consent of other parties to the operative documents, Mirant Mid-Atlantic cannot assign or sublease its interest under a facility lease unless certain requirements are met.

Philippines and Caribbean

Our subsidiaries in the Philippines and Caribbean have separate financing arrangements that are recourse to the specific subsidiary and are non-recourse to Mirant Corporation and its other subsidiaries. This debt is often secured by interests in the physical assets of the specific subsidiary, the major contracts and agreements of the subsidiary and, in some cases, the ownership interests in the specific subsidiary. The terms of the indebtedness of our Philippines and Caribbean subsidiaries typically limit the ability of such subsidiaries to incur additional indebtedness and make distributions.

The table set forth below shows the indebtedness, including capital leases, of our Philippines and Caribbean subsidiaries. See Note 12 to our consolidated financial statements contained elsewhere in this report for further discussion.

	Principal Amount Outstanding as of December 31, 2005	Maturity	Interest Rate
Mirant Sual Corporation	$ 452	2006 to 2012	LIBOR + 2.5% to 10.56%
Mirant Pagbilao Corporation	99	2006 to 2007	LIBOR + 2.15% to 10.25%
Jamaica Public Service Company Limited	339	2006 to 2030	7% to 12.51%
Mirant Trinidad Investments, LLC	73	2006	10.2%
Grand Bahama Power Company Limited	43	2006 to 2014	5.625%or LIBOR + 1.125%
Mirant Grand Bahama Limited	12	2006 to 2011	LIBOR + 1.25%
Mirant Curacao Investments Ltd.	17	2006 to 2007	9% to 10.15%

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 two activities: (i) the hedging and proprietary trading activities of Mirant Energy Trading; and (ii) capital expenditures required to keep our power generation facilities in operation.

Collateral requirements. The asset hedging and, to a lesser extent, proprietary trading activities of Mirant Energy Trading represent a significant need for liquidity and capital resources. These liquidity requirements are primarily driven by margin and collateral posting requirements with counterparties and disbursement and receipt timing (*i.e.*, buying fuel before receiving energy revenues). As of December 31, 2005, we had approximately $987 million of posted cash collateral and $58 million of letters of credit outstanding primarily to support our asset hedging 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. We do not assume that we will be provided with unsecured credit from third parties in budgeting our working capital requirements.

Capital Expenditures. Capital expenditures were $174 million, $159 million and $493 million for the years ended December 31, 2005, 2004 and 2003, respectively. Our capital expenditures for 2006 are expected to be approximately $410 million. For a more detailed discussion of environmental expenditures we expect to incur in the future, see Item 1. Business.

Debt service. At December 31, 2005, we had approximately $3.7 billion of long-term debt and had an additional $700 million as of March 3, 2006. Our expected annual interest expense is approximately $292 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 approximately $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.

JPS has approximately $131 million of indebtedness maturing in the third quarter of 2006. It is management s intention to refinance these loans, on a long-term basis, on or before the repayment dates and management is currently in an advanced stage of negotiation with prospective lenders to effect this refinancing. In addition, JPS had a working capital need primarily as a result of higher than anticipated system losses and the non-recovery of hurricane repair costs. In October 2005, an indirect subsidiary of Mirant agreed to provide JPS with a subordinated loan of up to $12 million. JPS executed a working capital credit facility in December 2005. JPS has drawn $20 million under that facility and used $7 million of those funds to repay in full the amounts outstanding under the shareholder subordinated loan.

Mirant Trinidad Investments, LLC (MTI) issued $100 million of 7.017% notes (MTI notes) pursuant to an indenture dated January 30, 2006. The MTI notes will require interest to be paid semiannually and the principal to be payable in a single installment at 100% of the principal amount thereon on February 1, 2016. The net proceeds, excluding fees and expenses related to the issuance of the MTI notes, were used to repay $73 million aggregate principal amount of MTI s outstanding 10.20% notes due January 31, 2006. The remaining net proceeds will be used by MTI to partially finance its 39% ownership share of PowerGen s expansion project. The MTI notes will be secured by a pledge and assignment by MTI of its shares of common stock issued by PowerGen and by certain other collateral. The MTI notes will be solely the obligation of MTI without recourse to any other Mirant entity or to PowerGen.

Under the financing agreements for the Sual project, Mirant Sual is restricted from paying dividends and making other subordinated loan payments, if any, if it does not comply with the required debt service coverage ratio. Primarily because of the expiration of its income tax holiday in October 2005, Mirant Sual

is not expected to comply with the required debt service coverage ratio in 2006. It expects to be able to meet the debt service coverage ratio in 2007. As a result, Mirant Sual s cash will not be available to us for use in 2006. As of December 31, 2005, Mirant Sual had a cash balance of approximately $81 million.

Sual put option. The remaining minority shareholder of Mirant Sual having ownership of 5.15% submitted its put option notice on December 1, 2005. The put option transaction is expected to be completed during the first quarter of 2006 with an estimated cost of $35 million to $39 million. Upon completion, we will have 100% ownership in the Sual project.

Cash Flows

Operating Activities

Cash provided by operating activities decreased $38 million for the year ended December 31, 2005, compared to the same period in 2004. Our cash provided by operating activities is volatile as a result of seasonality, changes in energy prices and fluctuations in our working capital requirements. Most notably, when we enter into transactions to economically hedge our expected generation output or fuel requirements and those positions move out-of-the money, we are required to post cash collateral due to our credit rating.

Net cash provided by operating activities excluding the changes in operating assets and liabilities increased by $59 million in 2005 primarily due to:

- an increase of $302 million in gross margin, excluding unrealized gains/losses and TPA amortization, due to a strong performance from our operations in the third quarter of 2005 and the expirations of the TPAs, partially offset by lower generation volumes and narrower conversion spreads in our United States operations in the first six months of 2005;

- a decrease of $64 million related to an increase in payments related to the bankruptcy proceedings; and

- a decrease of $179 million primarily related to increased operations and tax expenses.

See Results of Operations section of Item 7. Management s Discussion and Analysis for further discussion.

In 2005, changes in operating assets and liabilities required $303 million in cash. Additional net collateral used to support commercial operations was $305 million. The large collateral and margin requirements are due to significant increases in energy prices in the third quarter of 2005 that resulted in unrealized losses on our forward power sales contracts. Other working capital requirements for 2005 relate primarily to increases in other assets of $46 million, increases in other current assets of $27 million and increases in inventories of $22 million due to rising commodity prices. Sources of working capital include increase in taxes accrued of $78 million, primarily related to New York property taxes that have not been paid.

In 2004, changes in operating assets and liabilities required $206 million in cash and included net collateral used to support commercial operations of $121 million. These amounts were posted when energy prices moved against hedges that we entered into in order to economically hedge our expected generation output and fuel requirements. Other working capital requirements for 2004 related primarily to inventories that have increased due to rising commodity prices, primarily SO2 allowances used in our Mid-Atlantic power plants.

Investing Activities

In 2005, we had capital expenditures of $174 million primarily related to our Caribbean and Mid-Atlantic facilities. We received $63 million in proceeds from the sale of Coyote Springs 2 and $4 million in remaining proceeds from the 2004 sale of the Bowline expansion project gas turbines. We also received $85 million, $27 million and $23 million in proceeds from the sales of our Wrightsville generating facility, Mint Farm and Wyandotte suspended construction projects, respectively. In the fourth quarter of 2005, we received proceeds of $48 million related to the sale of a portion of our investment in a company that provides an electronic commerce platform for the purchase and sale of energy commodities.

In January 2006, MTI funded $39 million into an escrow account as required under the Amended and Restated PowerGen Shareholder Agreement and Shareholder Loan. PowerGen will draw from the escrow account to fund MTI s share of a 208 MW construction project. PowerGen is expected to begin drawing on the account in February 2006 and is expected to complete the project within approximately one year.

In 2004, we had capital expenditures of $159 million primarily related to our Caribbean and Mid-Atlantic facilities. We received $42 million in proceeds from the disposal of three natural gas turbines related to a suspended construction project. Our Philippine business paid $21 million to acquire an additional interest in the Sual project after a minority shareholder exercised its put option. We also paid $12 million to a third party to exit our Canadian natural gas transportation agreements and certain natural gas marketing contracts.

Financing Activities

In 2005, we had proceeds from the issuance of debt of $125 million. Of the $125 million, $100 million represented pre-petition letters of credit being drawn upon by counterparties and banks. The remaining debt proceeds of $25 million in 2005 were related to our Caribbean operations. We repaid long-term debt of $199 million consisting primarily of $159 million of debt related to our Philippine operations and $37 million of debt related to our Caribbean operations. Our Caribbean operations received a net $19 million in proceeds from short-term debt. Cash deposited in the debt service reserves related to our Philippine operations decreased by $25 million. We paid $16 million of dividends to minority interest holders.

On December 23, 2005, our subsidiary Mirant North America completed a note offering for $850 million of 7.375% senior unsecured notes due 2013. The funds from this issuance were initially placed in escrow and were released from escrow on January 3, 2006, upon consummation of the Plan.

In 2004, we had proceeds from the issuance of debt of $376 million, which included $318 million of pre-petition letters of credit being drawn upon by counterparties and banks. The drawing of Mirant Debtor letters of credit created a liability subject to compromise. The remaining debt proceeds of $58 million were related to our Caribbean operations. We repaid long-term debt of $218 million consisting primarily of $159 million of debt related to our Philippine operations and $56 million of debt related to our Caribbean operations. Cash deposited in the debt service reserves increased $154 million primarily due to $161 million of letters of credit drawn upon in 2004 in our Philippine operations. We paid $17 million of dividends to minority interest holders, and our Jamaican operations repaid $14 million of short-term debt.

Total Cash, Cash Equivalents and Credit Facility Availability

The table below sets forth total cash, cash equivalents and availability of Mirant Corporation and its subsidiaries as of December 31, 2005 and as of December 31, 2004 (in millions):

	December 31, 2005	**December 31, 2004**
Cash and Cash Equivalents:		
Mirant Corporation	$ 354	$ 276
Mirant Americas Generation	129	167
Mirant Mid-Atlantic	276	247
Mirant North America	19	207
Other United States subsidiaries	126	56
Philippines and Caribbean subsidiaries	647	532
Total cash and cash equivalents	1,551	1,485
Less: Cash required for operating, working capital or other purposes or restricted by subsidiaries debt agreements	326	274
Total available cash and cash equivalents	1,225	1,211
Available under the DIP Facility	249	263
Total cash, cash equivalents and credit facilities availability	$ 1,474	$ 1,474

On December 23, 2005, our subsidiary, Mirant North America, completed a note offering consisting of $850 million of 7.375% senior unsecured notes due 2013. The funds from this issuance were initially placed in escrow and were released from escrow on January 3, 2006, upon consummation of the Plan. In addition, on January 3, 2006, Mirant North America entered into an $800 million senior secured revolving credit facility and a $700 million senior secured term loan. The senior secured loan was made in a single draw upon closing and $200 million was deposited into a cash collateral account to support future issuance of letters of credit issued under the senior secured credit facilities. The DIP Facility was terminated on the emergence of the Mirant Debtors on January 3, 2006. In January 2006, we paid approximately $1,873 million of cash related to bankruptcy claims. As of March 3, 2006, total cash, cash equivalents and credit facility availability was $2,071 million, which includes $843 million of availability under the senior secured term loan and the senior secured revolving credit facility.

Maintaining sufficient liquidity in our business is crucial in order to mitigate the risk of future financial distress to the Company. 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.

We expect to incur capital expenditures of approximately $410 million in 2006. 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. This forecast does not include estimates for any expenditures that may be required by pending legislations,

including the Maryland Clean Power Rule. In the Philippines, the forecast assumes that the Philippine subsidiaries will make capital expenditures for the purpose of building and upgrading substations and transmission lines in order to support the energy supply business. These capital expenditures are expected to be funded primarily by operating cash flow. Additional capital expenditures are expected for the Philippines primarily for major maintenance and environmental projects at Pagbilao and Sual. In the Caribbean operations, new construction of generating facilities will be necessary to meet the growing energy demands and are expected to be funded by operating cash flow and project financings.

We anticipate that our cash flow from operations, total cash and cash equivalents, together with borrowings under Mirant North America s $800 million revolving credit facility will be sufficient to fund our operations during 2006 and beyond.

Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations

Our debt obligations, off-balance sheet arrangements and contractual obligations as of December 31, 2005, are as follows (in millions):

	Debt Obligations, Off-Balance Sheet Arrangements and Contractual Obligations by Year						
	Total	**2006**	**2007**	**2008**	**2009**	**2010**	**>5 years**
Operating leases	$ 2,645	$ 144	$ 146	$ 154	$ 168	$ 166	$ 1,867
Long-term debt	6,402	686	428	374	369	359	4,186
Claims payable and estimated claims accrual	1,948	1,948					
Purchase commitments:							
Long-term service agreements	572	12	24	27	26	39	444
Fuel and transportation commitments	560	300	220	5	5	4	26
Power purchase agreements (PPAs)	830	52	52	52	52	54	568
Other purchase commitments	161	161					
Total excluding liabilities subject to compromise	13,118	3,303	870	612	620	622	7,091
Liabilities subject to compromise	18						
Total debt obligations, off-balance sheet arrangements and contractual obligations	$ 13,136						

Operating leases are off-balance sheet arrangements and are discussed in Note 17 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 12 to our consolidated financial statements contained elsewhere in this report. Long-term debt also includes interest accrued on debt assuming no refinancing and a LIBOR curve as of January 11, 2006. In addition to the amounts shown above, on January 3, 2006, Mirant North America entered into an $800 million senior secured revolving credit facility and a $700 million senior secured term loan. The annual scheduled maturities and interest accrued on the $700 million are: $53 million for 2006, $52 million for 2007, $52 million for 2008, $51 million for 2009, $51 million for 2010 and $752 million for 2011 and thereafter. The draws on the $800 million senior secured revolving credit facility were repaid in January and February 2006.

Claims payable and estimated claims accrual includes primarily allowed bankruptcy claims and estimated unresolved bankruptcy claims that are to be settled in cash. It also includes accruals related to professional fees associated with the bankruptcy proceedings. Approximately $1,873 million of this liability was paid in cash in January, 2006.

Long-term service agreements are discussed in Note 17 to our consolidated financial statements contained elsewhere in this report. These amounts represent our total estimated commitments under our long-term service agreements associated with turbines installed or in storage.

Fuel and transportation commitments are discussed in Note 17 to our consolidated financial statements contained elsewhere in this report. These amounts relate primarily to long-term coal agreements and other fuel purchase and transportation agreements. The fair value of certain contracts is included in price risk management assets or price risk management liabilities on our consolidated balance sheets. In the first quarter of 2006, we expect to enter into additional significant coal commitments.

PPAs are discussed in Note 18 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 total remaining MWh commitment at contractual prices. These contracts are accounted for as derivatives. The fair value of certain agreements as of December 31, 2005, 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 are on the consolidated balance sheets and are discussed in Note 3 to our consolidated financial statements contained elsewhere in this report. As of December 31, 2005, liabilities subject to compromise relate only to our New York subsidiaries that remain in bankruptcy.

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. It is our view that the following critical accounting policies and the underlying estimates and judgments involve a higher degree of complexity than others do. We discussed the selection of and application of these accounting policies with the Audit Committee of the Board of Directors and our independent auditors.

Fresh Start Applicability

In connection with our emergence from bankruptcy, we would be required under Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code* (SOP 90-7) to adopt fresh start reporting under certain conditions. Fresh start reporting requires the debtor to use current fair values in its balance sheet for both assets and liabilities and to eliminate all prior earnings or deficits. The two requirements to fresh start reporting are:

- the reorganization value of the company s assets immediately before the date of confirmation of the plan of reorganization is less than the total of all post-petition liabilities and allowed claims; and
- the holders of existing voting shares immediately before confirmation receive less than 50% of the voting shares upon emergence.

We refer to these requirements as the fresh start applicability test. For purposes of applying the fresh start applicability test, reorganization value is defined in the glossary of SOP 90-7 as the value attributed to the reconstituted entity, as well as the expected net realizable value of those assets that will be disposed before reconstitution occurs. Therefore, this value is viewed as the fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring.

In most bankruptcy proceedings, the reorganization value is determined through the court process; it is either negotiated by the parties or ordered by the court if the parties cannot agree to a value. In the bankruptcy proceedings of the Mirant Debtors, no reorganization value was determined by the Bankruptcy Court or agreed upon by the parties.

In order to determine our reorganization value for purposes of the fresh start applicability test, we employed a market-based approach that incorporates the trading value of the Mirant Debtors publicly traded debt and equity securities in the days preceding the confirmation date of the Plan. We deem that this approach is appropriate as it is an objective and timely measurement of the fair value of the entity. We disclosed this intended approach in Exhibit D of the Disclosure Statement, which was approved by the Bankruptcy Court and used to solicit votes on the Plan.

The calculation of the reorganization value included the averaging of the trading value of our publicly traded debt and equity securities for the three days preceding the confirmation of the Plan on December 9, 2005. The trading values of debt were obtained through independent broker quotes for both us and Mirant Americas Generation. These prices were used to determine an implied value for their respective claim classes, as both public and private claims within each claim class receive identical treatment under the Plan. Then, the market value of our trust preferred securities and its common equity were added to the calculation.

In order to obtain an indication of total value of our debt and equity, debt of the non-bankrupt subsidiaries was included, as well as adjustments for items representing debt obligations that were not otherwise included in our claims. Finally, the total reorganization value of our assets was derived by adding non-interest bearing liabilities to the fair value of our debt and equity securities described above.

The result of the calculation indicated that we were not allowed to adopt fresh start reporting because the reorganization value immediately prior to the confirmation date exceeded the total of post-petition liabilities and allowed claims. As a result, our assets and liabilities were not adjusted to fair value; but rather liabilities compromised by the Plan are stated at present values of amounts to be paid and forgiveness of debt are reported as an extinguishment of debt in accordance with SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64; Amendment of FASB Statement 13; and Technical Corrections,* (SFAS No. 145).

The applicability test of fresh start reporting was sensitive to changes in the price of the securities, and a decrease of approximately 2% in the average price of the securities for the period measured would have resulted in us being required to adopt fresh start reporting. The adoption of fresh start reporting would have had a material impact on our balance sheet at December 31, 2005, as well as succeeding statements of operations. Under fresh start reporting, the Company s assets and liabilities would be stated at fair value, including the Company s power generation facilities and identifiable intangible assets such as emissions credits and energy contracts. The depreciation and amortization associated with these assets would also differ materially from the Company s historical consolidated financial statements. In addition, the Company s accumulated deficit would have been eliminated. Therefore, the successor Company under fresh start reporting would not have been comparable to the predecessor Company prior to the application of fresh start reporting.

See Note 3 to our consolidated financial statements for further information on our accounting while in bankruptcy.

Accounting for Energy Trading and Marketing Activities

Our United States businesses use derivatives and other energy contracts to economically hedge our electricity generation assets and to engage in proprietary trading activities. We use a variety of derivative contracts, such as futures, swaps, forwards 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. The fair value of such contracts is included in price risk management assets and liabilities in our consolidated balance sheets. A limited number of transactions do not meet the definition of a derivative or are considered normal purchases or normal sales, a permissible scope exception under SFAS No. 133. Thus, such transactions qualify for the use of accrual accounting.

Determining the fair value of derivatives involves significant estimates based largely on the mid-point of quoted market prices. 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. Our modeling techniques include assumptions for market prices, correlation and volatility, such as using the prices of one delivery point to calculate the price of the contract s delivery point. 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 are also impacted 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 the 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.

The amounts recorded as revenue 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, 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 the derivative instruments, a significant change in estimate could have a material impact on our results of operations.

See Note 6 to our consolidated financial statements for further information on financial instruments related to energy trading and marketing activities.

Income Taxes

We currently record a tax provision for foreign income taxes and federal alternative minimum tax as appropriate but record no tax benefit for losses for federal and state income tax purposes in the United States. We 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. If necessary, deferred tax assets are reduced by a valuation allowance to an 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. We must make significant estimates related to the generation of future taxable income during the periods in which the temporary differences will be deductible when determining the amount of the valuation allowance. At December 31, 2005, we had a valuation allowance of approximately $2.6 billion primarily related to our U.S. net deferred tax assets.

As of December 31, 2005, we have approximately $3.7 billion of U.S. federal Net Operating Loss (NOL) carryforwards for financial reporting purposes with expiration dates from 2022 to 2025. Similarly, there is an approximate aggregate amount of $5.7 billion of state NOL carryforwards with various expiration dates (based on the application of apportionment factors and other state tax limitations) and $61 million of foreign NOL carryforwards. In 2005, we implemented a plan which resulted in the inclusion of unremitted foreign earnings in our U.S. taxable income for that year. As a result, available net operating losses were reduced by $1.4 billion as of year end 2005 in addition to a corresponding reduction in the deferred U.S. residual tax liability related to these earnings.

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 impacted by whether we elect NOL treatment under Internal Revenue Code Section (§) 382(l)(5) or § 382(l)(6). Under § 382(l)(5), we would have unlimited use of our 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. The § 382(l)(5) election would require the Company to reduce its NOLs to approximately $2.6 billion from $3.7 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. The Company will make the § 382(l)(5) or § 382(l)(6) election in its 2006 annual tax return filed in 2007.

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 a particular item 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 when a liability is recorded and when the related filing position is no longer subject to question. Management periodically reviews these matters and adjusts the liabilities recorded as appropriate.

The Philippine taxing authority has a pending regulation that will require companies to use their functional currency, rather than the Philippine Peso, in financial statements and books of accounts for internal revenue tax purposes. Since this regulation is still in draft form, the ultimate impact on Philippine operations cannot yet be determined. However, the potential impact may be a requirement to write-off approximately $84 million of deferred tax assets relating to unrealized foreign exchange losses. These unrealized foreign exchange losses may no longer be allowed as a tax deduction if the final regulations prescribe that income tax liabilities are calculated based on functional currency financial statements.

See Note 13 to our consolidated financial statements for further information on income taxes.

Asset Impairments

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. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* (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. 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 from that asset or in the case of assets we expect to sell, at fair value less costs to sell.

The determination of impairment requires management to apply judgment in estimating future energy prices, environmental and other 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.

These estimates and assumptions are subject to a high degree of uncertainty. 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.

Investments accounted for by the equity method are reviewed for impairment in accordance with Accounting Principles Board Opinion 18 (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 losses in value of equity investments based upon a comparison of fair value to carrying value.

Asset Retirement Obligations

We account for asset retirement obligations under SFAS No. 143 and under FIN 47, *Conditional Asset Retirements* (FIN 47). SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. FIN 47 expanded on SFAS 143 to include conditional asset retirement obligations that should be recorded when estimable. Upon initial recognition of a liability for an asset retirement obligation, the Company capitalizes an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 and FIN 47 are those obligations for which a requirement exists under enacted laws, statutes and written or oral contractions, including obligations arising under the doctrine of promissory estoppel.

We have identified certain retirement obligations within our power generation operations in the United States. These asset retirement obligations are primarily related to asbestos abatement at some of our generating facilities, equipment on leased property and other environmental obligations related to the closing of ash disposal sites.

Liabilities associated with asset retirement obligations are 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 weighted. We update liabilities associated with asset retirement obligations as significant assumptions change or as relevant new information becomes available. However, actual future costs to satisfy asset retirement obligations could differ materially from the current recorded liabilities.

Estimated Useful Lives

The estimated useful lives of our long-lived assets are used to compute depreciation expense, future asset retirement obligations, and are also used in 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. Estimated lives could be impacted by such factors as future energy prices, environmental regulations, various legal factors and competition. If the useful lives were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in the carrying value of tangible and intangible assets may result.

See Note 7 to our consolidated financial statements for further information on long-lived assets.

Goodwill and Indefinite-lived Intangible Assets

We evaluate our goodwill and indefinite-lived intangible assets for impairment at least annually and periodically if indicators of impairment are present. An impairment occurs when the fair value of a reporting unit is less than its carrying value including goodwill. For this test our reporting units are the United States, Philippines and Caribbean. The amount of the impairment charge, if an impairment exists, is calculated as the difference between the fair value of the reporting unit 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.

The accounting estimates related to determining the fair value of goodwill require management to make assumptions about cost of capital, future revenues, operating costs and forward commodity prices over the life of the assets. Our assumptions about future revenues, costs and forward prices require significant judgment because such factors have fluctuated in the past and will continue to do so in the future.

The results of our 2003 analysis indicated that goodwill related to our United States reporting unit was impaired. Accordingly, in the second quarter of 2003, we recorded an impairment charge of approximately $2.1 billion, representing the entire balance of goodwill attributable to our United States reporting unit.

The results of our 2004 analysis indicated that goodwill related to our Philippine reporting unit was impaired. Accordingly, in the fourth quarter of 2004, we recorded an impairment charge of approximately $582 million, representing the remaining balance of goodwill attributable to our Philippine reporting unit.

Due to impairments in 2003 and 2004, the only remaining goodwill at October 31, 2005, was $5 million related to the Caribbean reporting unit. We performed our annual test for goodwill impairment effective October 31, 2005 for our Caribbean reporting unit. The test was based upon the business plan completed in the fourth quarter of 2005. The combined subjectivity and sensitivity of our assumptions and estimates used in our goodwill impairment analysis could result in a reasonable person reaching a different conclusion regarding those critical assumptions and estimates.

In our Caribbean reporting unit, the fair value of the reporting unit exceeded the carrying value including goodwill at October 31, 2005, by $137 million. The cost of capital rate significantly impacts the fair value of our projected future cash flows in the Caribbean. We used a cost of capital of 11% in determining the present value of our projected future cash flows. The sensitivity of the fair value of our projected future cash flows is such that a 100 basis point change in the cost of capital rate would change the discounted value of our projected future cash flows by approximately $35 million, which still would not indicate an impairment.

See Note 8 to our consolidated financial statements for further information on goodwill and indefinite-lived intangible assets.

Pension and Other Postretirement Benefits

The Company accounts for its pension benefits and its postretirement healthcare benefits using actuarial models. The assumptions used in these models impact the expense and liabilities associated with our pension and postretirement healthcare plans.

One of the principal components of the net periodic pension calculation is the expected long-term rate of return on plan assets. The required use of expected long-term rate of return on plan assets may result in recognized pension income that is greater or less than the actual returns of those plan assets in any given year. Over time, however, the expected long-term returns are designed to approximate the actual long-term returns and therefore result in a pattern of income and expense recognition that more closely matches the pattern of the services provided by the employees. 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 determined and consideration of diversification and portfolio rebalancing is given.

The discount rate assumptions used for pension benefits and postretirement healthcare benefits accounting reflects the prevailing market rates for high-quality fixed-income debt instruments that, if the pension benefit obligation was settled at the measurement date would provide the necessary future cash flows to pay the benefit obligation when due.

The medical care cost trend rate used for postretirement healthcare benefits assumed that the long-term rate of increase for medical costs slows from the trend of actual costs observed in the past few years. A 1% annual increase or decrease in the assumed medical care cost trend rate would correspondingly increase or decrease total annual expense by approximately $1.5 million.

Estimates used to calculate expenses and liabilities related to these plans may differ significantly from actual results resulting in unrecognized actuarial gains or losses. When the accumulation of such gains or losses exceed 10% of the greater of plan obligations or plan assets, a portion of the unrecognized amount is recognized in retirement plan expense through a straight-line amortization.

See Note 14 to our consolidated financial statements for further information on employee benefit plan obligations.

Litigation

See Item 3. Legal Proceedings and Note 15 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 impact 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 generating business in 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 the 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 impacts 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 additional facility generation capacity 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 by 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 over-the-counter 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 a derivative are included in price risk management assets and liabilities on the accompanying consolidated balance sheets at December 31, 2005, and in liabilities subject to compromise at December 31, 2004. For a discussion of the litigation involving the Back-to-Back Agreement, see Note 15 to the consolidated financial statements. The determination of fair value considers various factors, including closing exchange or Over-the-Counter (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 at December 31, 2005, was seven months. The net notional amount, or net short position, of the price risk management assets and liabilities at December 31, 2005, was approximately 8 million equivalent MWh. These amounts do not include the impact of the financial swap transactions entered into by Mirant Mid-Atlantic in January 2006 described in Item 1. Business Business Segments United States Commercial Operations.

The following table provides a summary of the factors impacting the change in net fair value of the price risk management asset and (liability) accounts in 2005 (in millions):

	Proprietary Trading	**Asset Management**	**Back-to-Back Agreement**	**Total**
Net fair value of portfolio at December 31, 2004	$ 24	$ (51)	$	$ (27)
(Losses) gains recognized in the period, net	(2)	(184)		(186)
Contracts settled during the period, net	18	54		72
Back-to-Back Agreement			(443)	(443)
Net fair value of portfolio at December 31, 2005	$ 40	$ (181)	$ (443)	$ (584)

The net price risk management value at December 31, 2005, includes the Back-to-Back Agreement. This was included in liabilities subject to compromise at December 31, 2004. At December 31, 2005, this amount was reclassified as this liability was not resolved in the Plan. For further discussion see Note 6.

The fair values of our price risk management assets and liabilities, net of credit reserves, as of December 31, 2005, are included in the following table (in millions).

	Net Price Risk Management Assets		**Liabilities**		
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Net Value at December 31, 2005**
Electricity	$ 454	$ 61	$ (704)	$ (20)	$ (209)
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 reserve	(11)				(11)
Total	$ 608	$ 115	$ (849)	$ (458)	$ (584)

The net price risk management value at December 31, 2005, includes the Back-to-Back Agreement. This was included in liabilities subject to compromise at December 31, 2004. At December 31, 2005, this amount was reclassified as this liability was not resolved in the Plan.

The following table represents the net price risk management assets and liabilities by tenor as of December 31, 2005 (in millions):

	Back-to-Back Agreement	**All Other Agreements**
2006	$ (26)	$ (215)
2007	(25)	42
2008	(41)	11
2009	(35)	11
2010	(34)	10
Thereafter	(282)	
Net (liabilities) assets	$ (443)	$ (141)

In the Philippines, our business is largely conducted through fixed-price, long-term contracts denominated in U.S. dollars, under which the purchaser is responsible for supplying the fuel, thereby mitigating our exposures to both fluctuating commodity prices and foreign currencies in these businesses.

In the Caribbean, our generating facilities either operate as rate-regulated integrated utilities, or under long-term power sales agreements which contain energy cost adjustment clauses. These arrangements help mitigate our exposure to fluctuating commodity prices.

Value at Risk

Effective November 5, 2003, our Risk Management Policy prohibits the trading of certain products (e.g., natural gas liquids and pulp and paper) and contains limits related to our asset management and proprietary trading. Our Risk Management Policy establishes a value-at-risk (VaR) limit with respect to our proprietary trading activities of $7.5 million. There is no VaR limit with respect to our asset management activities, as these activities are only allowable if they reduce the commodity price exposure of our generation assets. We manage the market risks associated with our asset management activities in conjunction with the physical generation assets that they are designed to economically hedge. As a result, our asset management portfolio is not included for purposes of compliance with our Risk Management Policy.

We manage the price risk associated with asset management activities through a variety of methods. To ensure that economic hedge positions are risk reducing in nature, we measure the impact of each asset management transaction executed relative to the overall asset position, including the previously executed economic hedge transaction that it is designed to economically hedge. 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 various assumed holding periods and a 95% confidence interval, was $4 million for the year ended December 31, 2005, and the VaR at December 31, 2005, was $3 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 interval, our average portfolio VaR for the year ended December 31, 2005, was $2 million and the VaR at December 31, 2005, was $1 million. During the year ended December 31, 2005, the actual daily loss on a fair value basis exceeded the corresponding one-day VaR calculation eight times, which falls within our 95% confidence interval.

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 subject to variable interest rates through either term loans or the Mirant North America credit facility is approximately $1.7 billion. If the credit facility is fully drawn a 1% per annum increase in the average market rate would result in an increase in our annual interest expense of approximately $17 million.

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. 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 other comprehensive income (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 do not have any foreign exchange contracts outstanding at December 31, 2005, 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,		
	2005	**2004**	**2003**
	(in millions)		
Operating Revenues:			
Generation	**$ 3,447**	$ 3,998	$ 4,610
Integrated utilities and distribution	**737**	573	548
Total operating revenues	**4,184**	4,571	5,158
Cost of fuel, electricity and other products	**2,430**	2,619	3,184
Gross Margin	**1,754**	1,952	1,974
Operating Expenses:			
Operations and maintenance	**988**	1,001	1,083
Depreciation and amortization	**307**	307	339
Goodwill impairment losses		582	2,067
Long-lived asset impairment losses			1,339
Other impairment losses and restructuring charges	**23**	23	57
Loss (gain) on sales of assets, net	**18**	53	(46)
Total operating expenses	**1,336**	1,966	4,839
Operating Income (Loss)	**418**	(14)	(2,865)
Other (Expense) Income, net:			
Interest expense	**(1,511)**	(130)	(379)
Interest rate hedging losses			(110)
Gain on sales of investments, net	**45**		67
Equity in income of affiliates	**33**	26	33
Impairment losses on minority owned affiliates	**(23)**		
Interest income	**31**	11	24
Other, net	**(59)**	68	48
Total other (expense), net	**(1,484)**	(25)	(317)
Loss From Continuing Operations Before Reorganization Items, Income Taxes and Minority Interest	**(1,066)**	(39)	(3,182)
Reorganization items, net	**72**	259	290
Provision for income taxes	**123**	87	126
Minority interest	**23**	21	35
Loss From Continuing Operations	**(1,284)**	(406)	(3,633)
Loss from Discontinued Operations, net	**(7)**	(70)	(173)
Loss Before Cumulative Effect of Changes in Accounting Principles	**(1,291)**	(476)	(3,806)
Cumulative Effect of Changes in Accounting Principles	**(16)**		(29)
Net Loss	**$ (1,307)**	$ (476)	$ (3,835)
Pro forma basic and diluted loss per share:			
Loss from continuing operations	**$ (4.28)**	$ (1.35)	$ (12.11)
Discontinued operations	**$ (0.02)**	$ (0.24)	$ (0.58)
Cumulative effect of changes in accounting principles	**$ (0.06)**	$	$ (0.09)
Net loss	**$ (4.36)**	$ (1.59)	$ (12.78)

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

MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2005 (in millions)	2004
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 1,551**	$ 1,485
Funds on deposit	**1,729**	493
Receivables, net	**873**	771
Price risk management assets	**608**	209
Inventories	**372**	350
Prepaid expenses	**217**	253
Assets held for sale	**11**	245
Other	**59**	133
Total current assets	**5,420**	3,939
Property, Plant and Equipment, net	**6,015**	6,150
Noncurrent Assets:		
Intangible assets, net	**288**	276
Investments	**227**	248
Price risk management assets	**115**	112
Funds on deposit	**188**	210
Deferred income taxes	**315**	185
Other	**344**	304
Total noncurrent assets	**1,477**	1,335
Total assets	**$ 12,912**	$ 11,424
LIABILITIES AND STOCKHOLDERS EQUITY (DEFICIT)		
Current Liabilities:		
Short-term debt	**$ 32**	$ 15
Current portion of long-term debt	**394**	206
Claims payable and estimated claims accrual	**1,948**	
Accounts payable and accrued liabilities	**783**	725
Price risk management liabilities	**849**	286
Accrued taxes and other	**369**	174
Total current liabilities	**4,375**	1,406
Noncurrent Liabilities:		
Long-term debt	**3,307**	1,169
Price risk management liabilities	**458**	62
Deferred income taxes	**242**	346
Asset retirement obligations	**35**	11
Deferred revenue	**150**	126
Other	**299**	241
Total noncurrent liabilities	**4,491**	1,955
Liabilities Subject to Compromise	**18**	9,217
Minority Interest in Subsidiary Companies	**172**	164
Commitments and Contingencies		
Stockholders Equity (Deficit):		
Preferred stock, par value $.01 per share; authorized 100,000,000 in 2005; issued and outstanding: none for 2005		
Common stock, par value $.01 per share; authorized 1,500,000,000 in 2005; issued and outstanding: 300,000,000 for 2005 authorized 2,000,000,000 in 2004; issued and outstanding: 405,568,084 for 2004	**3**	4
Additional paid-in capital	**11,298**	4,918
Accumulated deficit	**(7,462)**	(6,155)
Accumulated other comprehensive income (loss)	**17**	(83)
Treasury stock, at cost: 100,000 shares for 2004		(2)
Total stockholders equity (deficit)	**3,856**	(1,318)
Total liabilities and stockholders equity (deficit)	**$ 12,912**	$ 11,424

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

MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (DEFICIT)

	Common Stock (in millions)	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Treasury Stock
Balance, December 31, 2002	$ 4	$ 4,899	$ (1,844)	$ (102)	$ (2)
Net loss			(3,835)		
Other comprehensive income				38	
Issuance of common stock		19			
Balance, December 31, 2003	4	4,918	(5,679)	(64)	(2)
Net loss			(476)		
Other comprehensive loss				(19)	
Balance, December 31, 2004	4	4,918	(6,155)	(83)	(2)
Net loss			(1,307)		
Cancellation of pre-reorganization common stock	(4)	(4,918)			2
Issuance of post-reorganization common stock	3	11,298			
Other comprehensive income				100	
Balance, December 31, 2005	**$ 3**	**$ 11,298**	**$ (7,462)**	**$ 17**	**$**

MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	For the Years Ended December 31, 2005 (in millions)	2004	2003
Net Loss	**$ (1,307)**	$ (476)	$ (3,835)
Other comprehensive income (loss), net of tax			
Cumulative translation adjustment	**74**	(17)	(41)
Unrealized gains on available-for-sale securities	**27**		
Reclassification of investment unrealized gains to earnings		(7)	
Unrealized gain on investments		5	3
Net change in fair value of derivative hedging instruments			(4)
Reclassification of derivative net gains to earnings			73
Share of other comprehensive income of affiliates			7
Other	**(1)**		
Other comprehensive income (loss), net of tax	**100**	(19)	38
Total Comprehensive Loss	**$ (1,207)**	**$ (495)**	**$ (3,797)**

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

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MIRANT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 2005	2004	2003
	(in millions)		
Cash Flows from Operating Activities:			
Net loss	**$ (1,307)**	$ (476)	$ (3,835)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Amortization of transition power agreements and other obligations (non-cash revenue)	**(14)**	(349)	(449)
Depreciation and amortization	**320**	320	359
Impairment losses and restructuring charges	**32**	639	3,640
(Gain) loss on sales of assets and investments	**(16)**	53	(92)
Non-cash post-petition interest expense	**1,376**		
Interest rate hedging losses			110
Equity in income of affiliates, net of dividends	**(17)**	(7)	(12)
Non-cash charges for reorganization items	**115**	168	260
Effects of plan of reorganization	**(283)**		
Minority interest	**22**	21	(70)
Cumulative effect of changes in accounting principles	**16**		29
Price risk management activities, net	**17**	(148)	126
Deferred income taxes	**4**	50	46
Other, net	**71**	6	(23)
Changes in operating assets and liabilities:			
Receivables, net	**(373)**	149	949
Other current assets	**(359)**	(153)	(91)
Other assets	**(46)**	23	(84)
Accounts payable and accrued liabilities	**381**	(194)	(787)
Taxes accrued	**78**	(22)	(10)
Other liabilities	**16**	(9)	(85)
Total adjustments	**1,340**	547	3,816
Net cash provided by (used in) operating activities	**33**	71	(19)
Cash Flows from Investing Activities:			
Capital expenditures	**(174)**	(159)	(493)
Cash paid for acquisitions		(21)	(61)
Issuance of notes receivable			(29)
Repayments on notes receivable		1	98
Proceeds from the sales of assets and minority owned investments	**258**	45	398
Cash paid related to disposition		(12)	
Other	**(5)**		(1)
Net cash provided by (used in) investing activities	**79**	(146)	(88)
Cash Flows from Financing Activities:			
Proceeds from (payments on) short-term debt, net	**19**	(14)	(36)
Proceeds from issuance of long-term debt	**125**	376	355
Repayment of long-term debt	**(199)**	(218)	(300)
Purchase of TIERS Certificates			(51)
Proceeds from issuance of common stock			2
Change in debt service reserve fund	**25**	(154)	9
Other	**(15)**	(17)	3
Net cash used in financing activities	**(45)**	(27)	(18)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(1)**		6
Net Increase (Decrease) in Cash and Cash Equivalents	**66**	(102)	(119)
Cash and Cash Equivalents, beginning of year	**1,485**	1,587	1,706
Cash and Cash Equivalents, end of year	**$ 1,551**	$ 1,485	$ 1,587
Supplemental Cash Flow Disclosures:			
Cash paid for interest, net of amounts capitalized	**$ 120**	$ 117	$ 372
Cash paid (refunds received) for income taxes	**$ 68**	$ 42	$ (7)
Cash paid for reorganization items	**$ 171**	$ 107	$ 56
Business Acquisitions:			
Fair value of assets acquired	**$**	$ 21	$ 61
Less cash paid		21	61
Liabilities assumed	**$**	$	$

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

MIRANT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2005, 2004 and 2003

1. Description of Business and Organization

Mirant Corporation and its subsidiaries (collectively, Mirant or the Company) is an international energy company whose revenues are primarily generated through the production of electricity in the United States, the Philippines and the Caribbean. As of December 31, 2005, the Company owned or leased approximately 17,500 megawatts (MW) of electric generating capacity.

Mirant Corporation was originally incorporated in Delaware on April 20, 1993. In conjunction with Mirant s emergence from Chapter 11, the Company s corporate structure changed. As a result, on January 3, 2006, substantially all of Mirant Corporation s assets were transferred to a new Delaware corporation which was then renamed Mirant Corporation (New Mirant) and the former company was transferred to a trust. New Mirant serves as the corporate parent of the business enterprise and pursuant to the Plan of Reorganization (the Plan) has no successor liability for any unassumed obligations of the former company.

Mirant manages its business through three principal operating segments: United States, Philippines and Caribbean. The Company s United States segment consists of the ownership, long-term lease and operation of power generation facilities and energy trading and marketing operations. The Philippine segment includes ownership, long-term lease or similar interest in eight power generation businesses. In the Philippines, approximately 90% of the revenues currently come from fixed capacity charges under long-term contracts that are paid without regard to the dispatch level of the plant. The Caribbean segment includes power generation businesses in Curacao and Trinidad and Tobago and integrated utilities in the Bahamas and Jamaica. The Company s operations in the Caribbean include fully integrated electric utilities, which generate power sold to residential, commercial and industrial customers.

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 accounting principles generally accepted in the United States of America (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, and 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. Majority or jointly-owned affiliates, which Mirant does not control, as well as interests in variable interest entities in which Mirant is not the primary beneficiary, are also accounted for using the equity method of accounting.

The Company has held a minority equity interest in Ilijan, a non-consolidated variable interest entity (VIE), since July 2000. The non-consolidated VIE primarily holds an interest in a generation facility and had total assets of approximately $116 million at December 31, 2005. The Company thinks 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, 2005, of approximately $61 million.

For the period subsequent to July 14, 2003 (the Petition Date), and various dates thereafter, the accompanying financial statements have been prepared in accordance with Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code* (SOP 90-7). Accordingly, all pre-petition liabilities subject to compromise have been segregated in the consolidated balance sheets for the years ended December 31, 2004 and December 31, 2005, and classified as liabilities subject to compromise at the estimated amounts of allowable claims. The United States Bankruptcy Court for the Northern District of Texas, Fort Worth Division (the Bankruptcy Court) confirmed the Plan pursuant to an order dated December 9, 2005 (the Confirmation Order), and waived the stay of the Confirmation Order. Accordingly, immediately upon the entry of the Confirmation Order, the terms of the Plan and Confirmation Order were deemed binding upon Mirant and 83 of its direct and indirect subsidiaries in the United States (collectively, the Mirant Debtors) and all other parties affected by the Plan. The Plan became effective on January 3, 2006. For financial reporting purposes, Mirant recorded the effects of the Plan on December 31, 2005. Estimated claims related to the Company s New York operations consisting of approximately 1,672 MW including Mirant Lovett, LLC (Mirant Lovett), Mirant Bowline, LLC (Mirant Bowline) and Mirant NY-Gen, LLC (Mirant NY-Gen), which will remain in bankruptcy, total $18 million as of December 31, 2005, and are included in liabilities subject to compromise in the consolidated balance sheets.

The implementation of the Plan resulted in, among other things, a new capital structure, the discharge of debt of the old Mirant, the satisfaction or disposition of various types of claims against the old Mirant, the assumption or rejection of certain contracts and the establishment of a new Board of Directors. In accordance with SOP 90-7, if the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all post-petition liabilities and allowed claims, and if the holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity, the entity must adopt fresh start reporting upon its emergence from Chapter 11. The calculation of the reorganization value included the trading value of the Company s debt and equity securities for the three days preceding the confirmation of the Plan on December 9, 2005.

The result of the calculation indicated that the Company would not be allowed to adopt fresh start reporting because the reorganization value immediately prior to the confirmation date exceeded the total post-petition liabilities and allowed claims. For further discussion of fresh start reporting see Critical Accounting Policies and Estimates.

Certain prior period amounts have been reclassified to conform to the current year financial statement presentation. All amounts are presented in U.S. dollars unless otherwise noted.

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;
- estimating liabilities resulting from the bankruptcy;
- 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.

Recently Adopted Accounting Standards

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations: an interpretation of FASB Statement No. 143.* FIN 47 expands the scope of asset retirement obligations to be recognized under Statement of Financial Accounting Standards (SFAS) No. 143 (SFAS No. 143) to include asset retirement obligations that may be uncertain as to the nature or timing of settlement. Upon initial recognition of a liability for an asset retirement obligation, the Company capitalizes an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present fair value and the capitalized cost is depreciated over the remaining useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 and FIN 47 are those conditional and unconditional obligations for which a requirement exists under enacted laws, statutes and written or oral contractions, including obligations arising under the doctrine of promissory estoppel. For further discussion see Cumulative Effect of Changes in Accounting Principles below.

FIN 47 was effective for financial statements ending after December 15, 2005. At December 31, 2005, the Company recorded conditional asset retirement obligations related to the retirement of United States generating facilities of $35 million. The cumulative effect of adopting FIN 47 was $16 million.

In December 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 153, *Exchanges of Productive Assets: an Amendment of APB Opinion No. 29,* (SFAS No. 153). SFAS No. 153 addresses the measurement of exchanges of certain nonmonetary assets. It amends APB Opinion No. 29, *Accounting for Nonmonetary Exchanges,* and requires that nonmonetary exchanges (except for certain exchanges of products or property held for sale in the ordinary course of business) be accounted for at the fair value of the assets exchanged, with gains or losses being recognized, if the fair value is determinable within reasonable limits and the transaction has commercial substance. The provisions of SFAS No. 153 are effective for transactions involving nonmonetary exchanges that occur in fiscal periods beginning after June 15, 2005. The Company has determined that certain exchanges of emissions allowances that the Company may periodically transact would qualify as nonmonetary exchanges under SFAS No. 153. For the year ended December 31, 2005, the Company identified certain transactions involving exchanges of emissions allowances of one vintage year for a different year. The adoption of SFAS No. 153 had no material impact on the Company s consolidated results of operations, cash flows or financial position as of December 31, 2005.

New Accounting Standard Not Yet Adopted

In December 2004, the FASB issued SFAS 123R, *Share-Based Payment* (SFAS 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. The provisions of the interpretation, as amended, are effective for financial statements issued for periods that begin on or after January 1, 2006. We will adopt SFAS 123R during the first quarter of 2006 and will use the modified prospective transition method. Under the modified prospective transition method, companies are 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 123 pro forma disclosures. For all awards that are granted, modified or settled after the date of adoption, they will be measured and accounted for in accordance with SFAS 123R with no restatement of prior periods.

Our unvested awards of stock-based compensation at December 31, 2005, were cancelled in conjunction with the Plan. As a result of the adoption of SFAS 123R on January 1, 2006, unvested awards will have no impact on earnings. However, we have issued various stock-based instruments to certain employees and others during the first quarter of 2006. These instruments will be accounted for under SFAS 123R. Based on the grants already made, pre-tax compensation expense related to stock based compensation is expected to be approximately $15 million in 2006. This amount will be reflected in the line item for operations and maintenance expense in the consolidated statement of operations. We do not anticipate making additional broad grants of stock-based instruments during 2006, although incremental insignificant grants are possible.

We use the Black-Scholes option-pricing model to measure the grant-date fair value of stock options. However, due to our Chapter 11 proceedings and other factors, we do not have historical information concerning stock price volatility for purposes of valuing stock option grants. Therefore, we intend to use implied volatility derived from peer group information.

Under our 2005 Omnibus Incentive Plan, we may grant nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, other stock-based awards and non-employee director awards. See Note 14 to our consolidated financial statements for further information on the 2005 Omnibus Incentive Plan.

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 independent system operator (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 megawatt hours (MWh) delivered, at the relevant day-ahead or real-time prices. When a long-term electric power agreement conveys the right to use the generating capacity of Mirant s plant to the buyer of the electric power, 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 generating 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 other comprehensive income (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. Any ineffectiveness relating to cash flow hedges is recognized currently in earnings. 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, 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 as one of three types, based on the business objective the instrument is expected to achieve: asset management, legacy and proprietary trading. All asset management, legacy and proprietary trading derivative activities 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, *Accounting for Derivative Instruments and Hedging Activities,* (SFAS No.133) and therefore qualify for 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

During the year ended December 31, 2003, revenue earned from a single customer did not exceed 10% of the Company s total revenues. During 2005 and 2004, revenue earned from the National Power Corporation (NPC) in the Philippines exceeded 10% of the Company s total revenues. In 2005, 2004 and 2003, Mirant earned a significant portion of its operating revenue and gross margin from the Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) energy market, where our Mirant Mid-Atlantic, LLC (Mirant Mid-Atlantic) generation facilities are located.

Concentration of Labor Subject to Collective Bargaining Agreements

Approximately 52% of the Company s employees are subject to collective bargaining agreements. Approximately 34% of the employees 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 in the accompanying consolidated balance sheets and amounted to $1.9 billion and $703 million at December 31, 2005 and 2004, respectively. For 2005, current and noncurrent funds on deposit are $1.7 billion and $188 million, respectively. For 2004, current and noncurrent funds on deposit are $493 million and $210 million, respectively. Restricted cash includes deposits with brokers and cash collateral posted with third parties to support the Company s commodity positions and deposits for debt service reserve requirements under Mirant s project financing in the Philippines. In addition, as of December 31, 2005, restricted cash included $853 million in escrow related to 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 at December 31, 2005 and 2004. 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 sulfur dioxide (SO_2) and nitrogen oxide (NO_x) 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 Environmental Protection Agency (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 range 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.

The Company has determined that certain exchanges of emissions allowances that the Company may periodically transact would 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 or the life of the cooperation period of the various energy conversion agreements. For the years ended December 31, 2005, 2004 and 2003, the Company incurred the following interest costs (in millions):

	Years Ended December 31,		
	2005	**2004**	**2003**
Total interest costs	$ 1,512	$ 131	$ 407
Capitalized and included in construction work in progress	(1)	(1)	(28)
Interest expense	$ 1,511	$ 130	$ 379

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 interest expense of approximately $1.4 billion in 2005 on liabilities subject to compromise.

Leasehold Interests

Certain of Mirant s Philippine power generation facilities are developed under build, operate and transfer agreements with government controlled agencies of the respective local country government. Under these agreements, Mirant builds power generation facilities, operates them for a period of years (a cooperation period) and transfers ownership to the government at the end of the cooperation period. During construction, the cost of these facilities is recorded as construction work in progress. Upon completion of a facility, its entire cost is reclassified to leasehold interests where the balance is amortized over the remaining term of the agreement.

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. An 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.

Environmental Remediation Costs

Mirant accrues for costs associated with environmental remediation obligations 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. 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, *Accounting for Income Taxes* (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. Cumulative losses in recent years are the most compelling form of negative evidence considered by management in this determination.

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, *Accounting for the Impairment or Disposal of Long-Lived Assets,* (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 the discounted future cash flows of the asset. 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

2005

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. At 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.

2003

In October 2002, the EITF reached a consensus on EITF Issue 02-03, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*, to rescind EITF Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. Accordingly, energy-related contracts that are not accounted for pursuant to SFAS No. 133, such as transportation contracts, storage contracts and tolling agreements, are required to be accounted for as executory contracts using the accrual method of accounting and not fair value. Energy-related contracts that meet the definition of a derivative pursuant to SFAS No. 133 continue to be carried at fair value. In addition, the EITF observed that accounting for energy-related inventory at fair value by analogy to the consensus on EITF Issue 98-10 is not appropriate and that such inventory is not to be recognized at fair value. As a result of the consensus on EITF Issue 02-03, all non-derivative energy trading contracts on the consolidated balance sheet as of January 1, 2003, that existed on October 25, 2002, and energy-related inventories that were recorded at fair value have been adjusted to historical cost resulting in a cumulative effect adjustment of $26 million, net of taxes, which was recorded in the first quarter of 2003.

The Company adopted SFAS No. 143, effective January 1, 2003, related to costs associated with legal obligations to retire tangible, long-lived assets. Asset retirement obligations are recorded at 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. In the first quarter of 2003, the Company recorded a charge as a cumulative effect of a change in accounting principle of approximately $3 million, net of tax, related to the adoption of this accounting standard.

Interest Rate Financial Instruments

Historically, Mirant s policy was to manage interest expense using a combination of fixed- and variable-rate debt. The Company also entered into interest rate swaps to hedge its exposure to changes in interest rates. For qualifying hedges, changes in the fair value of the swaps were deferred in OCI, net of tax, and were reclassified from OCI to interest expense as an adjustment of interest expense over the term of the debt. Gains and losses resulting from the termination of qualifying hedges prior to their stated maturities were recognized as interest expense ratably over the remaining term of the hedged debt instrument. For non-qualifying hedges, changes in fair values of the swaps were recognized currently in earnings. As a result of the Company s bankruptcy filing, the remaining interest expense related to the previously terminated qualifying interest rate hedges was recognized in the third quarter of 2003. The Company does not have any interest rate swaps outstanding at December 31, 2005.

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, $12 million and $8 million in 2005, 2004 and 2003, respectively. 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

Historical earnings per share information has not been presented. The Company does not perceive that this information is relevant in any material respect for users of its financial statements. In lieu of presenting historical earnings per share information, pro forma earnings per share data has been presented. See Note 20 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.

3. Bankruptcy Related Disclosures

On January 19, 2005, Mirant and 83 of its direct and indirect subsidiaries in the United States (collectively, the Mirant Debtors) filed a Plan and Disclosure Statement (the Disclosure Statement) with the Bankruptcy Court. The Bankruptcy Court confirmed the Plan pursuant to an order dated December 9, 2005 (the Confirmation Order). Accordingly, the terms of the Plan and Confirmation

Order were deemed binding upon the Mirant Debtors and all other parties affected by the Plan. The Plan became effective on January 3, 2006. For financial statement presentation purposes, Mirant recorded the effects of the Plan on December 31, 2005. Mirant s New York subsidiaries remain in bankruptcy.

The Plan included the following key elements:

- The business of the Mirant Debtors continued to operate in its current form, subject to certain internal structural changes including the organization of a new parent entity (New Mirant).

- In addition to amounts borrowed under Mirant North Americas senior secured revolving credit facility the consolidated business has approximately $4.4 billion of debt after emergence.

- The pre-petition intercompany claims between and among the Mirant Debtors were resolved as part of a global settlement.

- The holders of unsecured claims against the Consolidated Mirant Debtors received a pro rata share of:

- 96.25% of the shares of New Mirant common stock issued under the Plan, excluding: (i) 2.3% of shares of New Mirant common stock issued to certain holders of claims against the Mirant Americas Generation Debtors, and (ii) the shares reserved for issuance pursuant to the New Mirant employee stock programs; and

- the right to receive cash payments equal to 50% of the cash recoveries, if any, from certain designated avoidance actions. In connection with the Plan, MC Asset Recovery, LLC (MC Asset Recovery) was formed as a wholly-owned subsidiary on December 30, 2005, to prosecute, settle and/or liquidate certain avoidance actions. For further discussion, see Note 15 contained elsewhere in this document.

The holders of certain subordinated obligations had the right to receive 3.5% of the shares of New Mirant common stock (which shares are included in the 96.25% referred to above), to receive warrants to purchase an additional 5% of the shares of New Mirant common stock, and to participate pari passu with the holders of Mirant unsecured claims in the recoveries under the designated avoidance actions.

- The outstanding common stock in Mirant was cancelled and the holders thereof received:

- 3.75% of the shares of New Mirant common stock (subject to the exclusions noted above for Mirant s general unsecured creditors, as applicable);

- warrants to purchase up to an additional 10% of the shares of New Mirant common stock; and

- the right to receive cash payments equal to 50% of the recoveries, if any, from certain designated avoidance actions.

- The claims against the Consolidated Mirant Americas Generation Debtors were paid in full through:

- the reinstatement of the Mirant Americas Generation senior notes maturing in 2011, 2021 and 2031, and the payment of $452 million of accrued interest; and

- the issuance to all other holders of secured and unsecured claims against the Mirant Americas Generation Debtors of (a) approximately $1.35 billion in cash and (b) 2.3% of the shares of New Mirant common stock , subject to certain exclusions.

- Mirant contributed (or caused to be contributed) additional value to Mirant Americas Generation, including:

- the transfer on January 31, 2006, of certain assets and liabilities of the trading and marketing business to Mirant North America in return for $250 million of cash;

- commitments to make capital contributions: (a) through the issuance by Mirant Americas of up to $265 million of redeemable Series A Preferred Shares redeemable by Mirant Mid-Atlantic to fund environmental capital expenditures, and (b) through the issuance by Mirant Americas of $150 million of Series B Preferred Shares, redeemable by Mirant Americas Generation, to support the refinancing of its notes due 2011;

- the transfer of Mirant Potomac River, LLC (Mirant Potomac River) to Mirant Chalk Point, LLC (Mirant Chalk Point) a wholly-owned subsidiary of Mirant Mid-Atlantic, and the transfer of Mirant Peaker, LLC (Mirant Peaker) to Mirant Chalk Point and the subsequent merger of Mirant Peaker into Mirant Chalk Point; and

- the transfer of Mirant Zeeland, LLC (Mirant Zeeland) to Mirant North America.

- Mirant Mid-Atlantic assumed the Mirant Mid-Atlantic leveraged leases in accordance with the terms of the Plan and subject to the order of the Bankruptcy Court with respect to the interpretation of certain provisions of the leveraged lease documentation.

On January 3, 2006, substantially all of the assets of Mirant Corporation were transferred to New Mirant, which has no successor liability for any unassumed obligations of Mirant Corporation. On January 31, 2006, the trading and marketing business of Mirant Americas Energy Marketing, Mirant Americas Development Inc., Mirant Americas Production Company, Mirant Americas Energy Capital, LLC, Mirant Americas Energy Capital Assets, LLC, Mirant Americas Development Capital, LLC, Mirant Americas Retail Energy Marketing, L.P., and Mirant Americas Gas Marketing, LLC, (the Trading Debtors) was transferred to Mirant Energy Trading, which has no successor liability for any unassumed obligations of the Trading Debtors. After these transfers took place, Mirant Corporation and the Trading Debtors were transferred to a trust created under the Plan.

Liabilities Subject to Compromise

At December 31, 2005, amounts related to allowed claims and estimated unresolved claims that are to be settled in cash are $1.9 billion and are recorded in claims payable and estimated claims accrual on the accompanying consolidated balance sheets. Due to the confirmation of the Plan on December 9, 2005, the Company s liabilities subject to compromise as of December 31, 2005, relate only to that of its New York subsidiaries that remain in bankruptcy.

As of December 31, 2004, liabilities subject to compromise included certain liabilities incurred prior to the Petition Date. The amounts of the various categories of liabilities that were subject to compromise are set forth below. Such amounts represented the Company s estimates of known or potential claims against Mirant Debtors that were likely to be resolved in connection with the bankruptcy filings.

The amounts subject to compromise at December 31, 2005 and 2004 consisted of the following items (in millions):

	December 31,	
Items, absent the bankruptcy filings, that would have been considered current at:	**2005**	**2004**
Accounts payable and accrued liabilities	$ 18	$ 1,028
Current portion of long-term debt		3,112
Price risk management liabilities		80
Items, absent the bankruptcy filings, that would have been considered noncurrent at:		
Long-term debt		3,974
Price risk management liabilities		460
Note payable to Mirant Trust I		356
Other noncurrent liabilities		207
Liabilities subject to compromise	$ 18	$ 9,217

Debtor/Non-Debtor Financial Statements

Condensed combined financial statements of the Mirant Debtors and Non-Debtors are set forth below. In the condensed combined statements of operations, Mirant Debtors include all entities that filed for protection from creditors in 2003. Non-Debtors include the Company s businesses in the Caribbean and Philippines that are generally not affected by the bankruptcy filings, as well as certain non wholly-owned subsidiaries and the Mirant Canadian Subsidiaries which emerged from Creditors Arrangement Act in Canada creditor protection in May 2004. As the Mirant Debtors were operating as debtors-in-possession in bankruptcy throughout 2005, the condensed combined statement of operations data for 2003 through 2005 reflect the Mirant Debtors results of operations through December 31, 2005; whereas, for condensed balance sheet purposes such debtors, excluding the Mirant New York entities, are shown as non-debtors at December 31, 2005.

In the condensed combined balance sheet as of December 31, 2005, Mirant Debtors include the New York subsidiaries, which remain in bankruptcy. Non-Debtors include the Mirant Debtors that were part of the Plan confirmed on December 9, 2005, as well as the Company s Philippines and Caribbean operations.

In the condensed combined balance sheet as of December 31, 2004, Mirant Debtors include all entities that filed for protection from creditors in 2003. Non-Debtors include the Company s Philippines and Caribbean operations.

Condensed Combined Statement of Operations Data
For the Year Ended December 31, 2005
(in millions)

	Debtors	Non-Debtors	Consolidation/ Elimination Entries	Consolidated
Operating revenues	$ 2,964	$ 1,227	$ (7)	$ 4,184
Cost of fuel, electricity and other products	1,996	440	(6)	2,430
Operating expenses	917	420	(1)	1,336
Operating income	51	367		418
Other (expense) net	(1,365)	10	(129)	(1,484)
Reorganization items, net	66		6	72
(Benefit) provision for income taxes	(96)	219		123
Minority interest		23		23
(Loss) income from continuing operations	(1,284)	135	(135)	(1,284)
Loss from discontinued operations, net of tax	(7)			(7)
Cumulative effect of changes in accounting principles, net of tax	(16)			(16)
Net (loss) income	$ (1,307)	$ 135	$ (135)	$ (1,307)

Condensed Combined Statement of Operations Data
For the Year Ended December 31, 2004
(in millions)

	Debtors	Non-Debtors	Consolidation/ Elimination Entries	Consolidated
Operating revenues	$ 3,529	$ 1,061	$ (19)	$ 4,571
Cost of fuel, electricity and other products	2,332	304	(17)	2,619
Operating expenses	958	1,010	(2)	1,966
Operating income (loss)	239	(253)		(14)
Other (expense) income net	(161)	(52)	188	(25)
Reorganization items, net	250	6	3	259
Provision (benefit) for income taxes	282	(195)		87
Minority interest		21		21
(Loss) income from continuing operations	(454)	(137)	185	(406)
Loss from discontinued operations, net of tax	(22)	(48)		(70)
Net (loss) income	$ (476)	$ (185)	$ 185	$ (476)

Condensed Combined Statement of Operations Data
For the Year Ended December 31, 2003
(in millions)

	Debtors	Non-Debtors	Consolidation/ Elimination Entries	Consolidated
Operating revenues	$ 4,158	$ 1,031	$ (31)	$ 5,158
Cost of fuel, electricity and other products	2,923	279	(18)	3,184
Operating expenses	4,453	392	(6)	4,839
Operating income (loss)	(3,218)	360	(7)	(2,865)
Other (expense) income net	(225)	14	(106)	(317)
Reorganization items, net	290			290
(Benefit) provision for income taxes	(110)	236		126
Minority interest	12	23		35
(Loss) income from continuing operations	(3,635)	115	(113)	(3,633)
Loss from discontinued operations, net of tax	(171)	(2)		(173)
Cumulative effect of changes in accounting principles, net of tax	(29)			(29)
Net (loss) income	$ (3,835)	$ 113	$ (113)	$ (3,835)

Condensed Combined Balance Sheet Data
December 31, 2005
(in millions)

	Debtors	Non-Debtors	Consolidation/ Elimination Entries	Consolidated
Current assets	$ 31	$ 5,389	$	$ 5,420
Intercompany receivables	149	98	(247)	
Property, plant and equipment, net	502	5,513		6,015
Intangible assets, net		288		288
Investments		620	(393)	227
Other	4	958		962
Total assets	$ 686	$ 12,866	$ (640)	$ 12,912
Liabilities not subject to compromise:				
Current liabilities	168	4,207		4,375
Intercompany payables	36	149	(185)	
Other noncurrent liabilities	9	1,175		1,184
Long-term debt		3,307		3,307
Liabilities subject to compromise	80		(62)	18
Minority interest		172		172
Stockholders equity	393	3,856	(393)	3,856
Total liabilities and stockholders equity	$ 686	$ 12,866	$ (640)	$ 12,912

Condensed Combined Balance Sheet Data
December 31, 2004
(in millions)

	Debtors	Non-Debtors	Consolidation/ Elimination Entries	Consolidated
Current assets	$ 2,940	$ 1,233	$ (234)	$ 3,939
Intercompany receivables	684	618	(1,302)	
Property, plant and equipment, net	3,960	2,190		6,150
Intangible assets, net	262	14		276
Investments	2,101	231	(2,084)	248
Other	290	521		811
Total assets	$ 10,237	$ 4,807	$ (3,620)	$ 11,424
Liabilities not subject to compromise:				
Current liabilities	971	436	(1)	1,406
Intercompany payables	526	685	(1,211)	
Other noncurrent liabilities	333	454	(1)	786
Long-term debt	185	984		1,169
Liabilities subject to compromise	9,540		(323)	9,217
Minority interest		164		164
Stockholders (deficit) equity	(1,318)	2,084	(2,084)	(1,318)
Total liabilities and stockholders equity	$ 10,237	$ 4,807	$ (3,620)	$ 11,424

Condensed Combined Statement of Cash Flow Data
For the Year Ended December 31, 2005
(in millions)

	Debtors	Non-Debtors	Consolidation/ Elimination Entries	Consolidated
Net cash (used in) provided by:				
Operating activities	$ (303)	$ 334	$ 2	$ 33
Investing activities	79			79
Financing activities	96	(139)	(2)	(45)
Effect of exchange rate changes on cash and cash equivalents		(1)		(1)
Net (decrease) increase in cash and cash equivalents	(128)	194		66
Cash and cash equivalents, beginning of year	953	532		1,485
Cash and cash equivalents, end of year	$ 825	$ 726	$	$ 1,551
Cash paid for reorganization items	$ 168	$ 3	$	$ 171

Condensed Combined Statement of Cash Flow Data
For the Year Ended December 31, 2004
(in millions)

	Debtors	Non-Debtors	Consolidation/ Elimination Entries	Consolidated
Net cash (used in) provided by:				