MIRANT CORP
Form 10-K
March 15, 2005

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, 2004

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)		**www.mirant.com** Web Page

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

None

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

Common Stock, par value $0.01 per share

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes o No

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

Indicate by check mark whether the registrant is an accelerated filer (as defined by Rule 12b-2 of the Act). x Yes o No

Aggregate market value of voting stock held by non-affiliates of the registrant was approximately $121,700,425 on June 25, 2004 (based on $0.30 per share, the closing price in the daily composite list for transactions on the Pink Sheets Electronic Quotation Service for that day). As of February 25, 2005, there were 405,468,084 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, believe, estimate, 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:

General Factors

- 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 subject;

- the failure of our assets to perform as expected;

- our pursuit of potential business strategies, including the disposition or utilization of assets, suspension of construction or internal restructuring;

- 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 the markets of our subsidiaries and affiliates;

- 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 (OTC) 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 hedging and optimization activities as expected;

- our ability to borrow additional funds and access capital markets;

- weather and other natural phenomena;

- 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; and

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

Bankruptcy-Related Factors

- the actions and decisions of our creditors and of other third parties with interests in the voluntary petitions for reorganization filed with the U.S. Bankruptcy Court for the Northern District of Texas, Fort Worth Division (the Bankruptcy Court) on July 14, 2003, July 15, 2003, August 18, 2003, October 3, 2003 and November 18, 2003, by Mirant Corporation and substantially all of its wholly-owned and certain non-wholly-owned U.S. subsidiaries under Chapter 11 (Chapter 11) of the U.S. Bankruptcy Code (the Bankruptcy Code), including actions taken by our creditors and other third parties with respect to our proposed plan of reorganization, filed with the Bankruptcy Court on

January 19, 2005, and any amendments thereto (the Plan);

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- our ability to satisfy the conditions precedent to the effectiveness of our proposed Plan, including our ability to secure the necessary financing commitments;
- the effects of the Chapter 11 proceedings on our liquidity and results of operations;
- the instructions, orders and decisions of the Bankruptcy Court, the U.S. District Court for the Northern District of Texas, the U.S. Court of Appeals for the Fifth Circuit and other legal and administrative proceedings, settlements, investigations and claims;
- our ability to operate pursuant to the terms of our debtor-in-possession financing agreement;
- our ability to successfully reject unfavorable contracts;
- the disposition of unliquidated claims against us;
- our ability to obtain and maintain normal terms with vendors and service providers and to maintain contracts that are critical to our operations;
- possible decisions by our pre-petition creditors who may receive Mirant common stock upon our emergence from bankruptcy and therefore may have the right to select our board members and influence certain aspects of our business operations;
- the effects of changes in our organizational structure in conjunction with our emergence from Chapter 11 protection; and
- the duration of our Chapter 11 proceedings.

The ultimate outcome of matters with respect to which we make forward-looking statements and the terms of any reorganization plan ultimately confirmed can affect the value of our various pre-petition liabilities, common stock and other securities. No assurance can be given as to what values, if any, will be ascribed in the bankruptcy proceedings to each of these constituencies. The proposed Plan could result in holders of our common stock receiving no distribution on account of their interests and cancellation of their interests. Accordingly, we urge that appropriate caution be exercised with respect to existing and future investments in our common stock or any claims relating to pre-petition liabilities or other Mirant securities.

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.

Factors that Could Affect Future Performance

Other factors that could affect our future performance (business, financial condition or results of operations and cash flows) are set forth under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Factors that Could Affect Future Performance.

PART I

Item 1. *Business*

Overview

We are an international energy company incorporated in Delaware on April 20, 1993. Our revenues are primarily generated through the production of electricity in the United States, the Philippines and the Caribbean. As of December 31, 2004, we owned or leased approximately 18,000 megawatts (MW) of electric generating capacity.

We manage our business through two principal operating segments: North America and International. Our North America segment consists of the ownership and operation of power generation facilities and energy trading and marketing operations. The International segment includes power generation businesses in the Philippines, Curacao and Trinidad and Tobago, and integrated utilities in the Bahamas and Jamaica. The table below summarizes selected 2004 financial information about our business segments.

	Revenues ($ in millions)	%	Gross Margin	%	Operating Income (Loss)	Total Assets	Cash from Operating Activities
Business Segment:							
North America	$ 3,522	77 %	$ 1,196	61 %	$ 242	$ 9,354	$ (168)
International	1,050	23	756	39	(246)	4,730	371
Corporate and Eliminations					(14)	(2,660)	(132)
Total	$ 4,572	100 %	$ 1,952	100 %	$ (18)	$ 11,424	$ 71

The annual, quarterly and current reports, and any amendments to those reports, that we file with or furnish to the SEC are available free of charge on our website at www.mirant.com as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. General information about us, including our Corporate Governance Guidelines, the charters for our Audit, Compensation, and Nominating and Governance Committees, and our Code of Ethics and Business Conduct, can be found at www.mirant.com. We will provide print copies of these documents to any shareholder upon written request to Corporate Secretary, Mirant Corporation, 1155 Perimeter Center West, Atlanta, Georgia 30338. 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.

Proceedings under Chapter 11 of the Bankruptcy Code

On July 14, 2003 and July 15, 2003 (collectively, the Petition Date), Mirant and 74 of its wholly-owned subsidiaries in the United States (collectively, the Original Debtors) filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. On August 18, 2003, October 3, 2003 and November 18, 2003, four additional wholly-owned subsidiaries and four affiliates of Mirant commenced Chapter 11 cases under the Bankruptcy Code (together with the Original Debtors, the Mirant Debtors). The Chapter 11 cases of the Mirant Debtors are being jointly administered for procedural purposes only under the case caption 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 (CCAA), 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. The accounting for their emergence is reflected in this report and did not have a material impact on our operating results.

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

The Mirant Debtors are operating 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, is authorized under the Bankruptcy Code to continue to operate as an ongoing business, but may not engage in transactions outside the ordinary course of business without the prior approval of the Bankruptcy Court.

The Office of the United States Trustee has established a committee of unsecured creditors for Mirant Corporation and a committee of unsecured creditors for Mirant Americas Generation, LLC (collectively, the Creditor Committees). The Office of the United States Trustee also has established a committee of equity security holders of Mirant Corporation (the Equity Committee and, collectively with the Creditor Committees, the Statutory Committees). Pursuant to an order of the Bankruptcy Court, the Office of the United States Trustee appointed an examiner (the Examiner) in these cases to analyze certain potential causes of action and to act as a mediator with respect to certain disputes that may arise among the Mirant Debtors, the Statutory Committees and other parties in interest.

Subject to certain exceptions in the Bankruptcy Code, the Chapter 11 filings automatically stayed the initiation or continuation of most actions against the Mirant Debtors, including most actions to collect pre-petition indebtedness or to exercise control over the property of the bankruptcy estates. As a result, absent an order of the Bankruptcy Court, creditors of the Mirant Debtors are precluded from collecting pre-petition debts and substantially all pre-petition liabilities are subject to compromise under a proposed plan or plans of reorganization in the bankruptcy proceedings. One exception to this stay of litigation is for an action or proceeding by a governmental agency to enforce its police or regulatory power.

On July 24, 2003, the Bankruptcy Court approved an interim procedure requiring certain direct and indirect holders of claims, preferred securities and common stock to provide at least ten days advance notice of their intent to buy or sell claims against the Mirant Debtors or shares in Mirant Corporation. The Bankruptcy Court entered a final order on September 17, 2003 and such order establishes notice procedures applicable only to those transactions with a person or entity owning (or, because of the transaction, resulting in ownership of) an aggregate amount of claims equal to or in excess of $250 million or such higher amount determined under the order and, with respect to shares, only those persons or entities owning (or, because of the transaction, resulting in ownership of) 4.75% or more of any class of outstanding shares. In addition, each entity or person that owns at least $250 million, or such higher amount determined under the order, of certain claims or preferred securities must provide Mirant and the Creditor Committees with notice of ownership information. The Court s orders also provide for expedited procedures to impose sanctions for a violation of its orders, including monetary damages and, in some cases, the voidance of any such transactions that violate the order. Upon election, a special regime allowing virtually unlimited trading of claims without having to provide notice thereof may be available to certain claimholders, although such electing claimholders may be required to sell a portion of their claims before a specific date. The emergency and final relief was sought to prevent potential trades of claims of stock that could negatively impact the availability of the Mirant Debtors U.S. net operating loss carryforwards and other tax attributes. The U.S. federal net operating loss carryforward is approximately $2.8 billion at December 31, 2004. Even with the relief that has been granted, Mirant cannot guarantee that it will be able to benefit from all, or any portion, of its U.S. federal net operating loss carryforwards and other tax attributes. Similarly, there are approximately $3.9 billion of state net operating loss carryforwards. See Critical Accounting Policies and Estimates for further information.

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Under the Bankruptcy Code, the Mirant Debtors also have the right to assume, assign, or reject certain executory contracts and unexpired leases, subject to the approval of the Bankruptcy Court and satisfaction of certain other conditions. The Mirant Debtors are continuing to evaluate their executory contracts in order to determine which contracts will be assumed, assigned or rejected.

In response to a motion filed under section 502(c) of the Bankruptcy Code (the Estimation Motion) by the Mirant Debtors, the Bankruptcy Court entered an order establishing procedures for estimating proofs of claim under section 502(c) of the Bankruptcy Code that are binding for all purposes, including voting on, feasibility of and distribution under a Chapter 11 plan for the Mirant Debtors. As a result, the Mirant Debtors filed approximately sixty material claim objections and three notices of intent to contest claims.

Plan of Reorganization

On January 19, 2005, the Mirant Debtors filed a proposed Plan of Reorganization and Disclosure Statement (the Disclosure Statement) with the Bankruptcy Court. The proposed Plan sets forth a proposed structure of the Company at emergence and how the claims of creditors and stockholders are to be treated. If the Disclosure Statement is found by the Bankruptcy Court to contain adequate information, then we will solicit votes on the proposed Plan from those creditors, security holders and interest holders who are entitled to vote on the proposed Plan.

The proposed Plan implements and includes the following key elements:

- the business of the Mirant Debtors will continue to be operated in substantially its current form, subject to certain internal structural changes that the Mirant Debtors believe will improve operational efficiency, facilitate and optimize their ability to meet financing requirements and accommodate the enterprise s debt structure as contemplated at emergence;

- the original Mirant Debtors that are parties to the Chapter 11 proceedings, excluding Mirant Americas Generation, LLC (Mirant Americas Generation) and its subsidiaries (collectively, the Mirant Americas Generation Debtors), are substantively consolidated for all purposes under the proposed Plan;

- the Mirant Americas Generation Debtors are substantively consolidated for all purposes under the proposed Plan;

- the unsecured debt of the Mirant Americas Generation Debtors is to be paid in full through (i) the issuance to the lenders under the Mirant Americas Generation revolving credit facilities and the holders of Mirant Americas Generation senior notes maturing in 2006 and 2008 of (a) new debt securities of a newly formed intermediate holding company under Mirant Americas Generation (New Mirant Americas Generation Holdco) in an amount equal to 90% of the full amount owed to such creditors (as determined by the Bankruptcy Court) and (b) common stock in the new corporate parent of the Mirant Debtors (New Mirant) having a value equal to 10% of such amount owed; and (ii) the reinstatement of Mirant Americas Generation senior notes maturing in 2011, 2021 and 2031;

- to ensure the feasibility of the proposed Plan with respect to the Mirant Americas Generation Debtors and to resolve intercompany claims, the proposed Plan provides that additional value shall be contributed to Mirant Americas Generation, including the trading business (subject to an obligation to return a portion of the embedded capital in the trading business to Mirant), the Zeeland generating facility and commitments to make prospective capital contributions of up to $150 million (for refinancing) and $265 million (for sulfur dioxide capital expenditures);

- the prospective working capital requirements of Mirant Americas Generation will be met with the proceeds of a new first lien facility in the amount of at least $750 million;

- the bulk of the contingent liabilities of the Mirant Debtors associated with the California energy crisis and certain related matters will be resolved pursuant to a global settlement as described in Item 3. Legal Proceedings contained elsewhere in this report;

- substantially all of the assets of Mirant will be transferred to a new company to be formed pursuant to the proposed Plan, which will serve as the corporate parent of our business enterprise on and after the effective date of the proposed Plan and which shall have no successor liability for any unassumed obligations of Mirant Corporation, including any obligations to Potomac Electric Power Company (PEPCO) under the back-to-back agreement discussed under Item 3. Legal Proceedings ; similarly, the trading business shall be transferred to Mirant Energy Trading, LLC, which shall have no successor liability for any unassumed obligations of Mirant Americas Energy Marketing, L.P. (Mirant Americas Energy Marketing), including any obligations to PEPCO under the back-to-back agreement discussed under Item 3. Legal Proceedings ; and

- the outstanding common stock in Mirant Corporation will be cancelled and the holders thereof will receive any surplus value after creditors are paid in full, plus the right to receive a pro rata share of warrants issued by New Mirant if they vote to accept the proposed Plan.

At present, the proposed Plan has not been approved by any of the Statutory Committees. As such, the Mirant Debtors anticipate that negotiations (which, whether or not successful, could lead to material changes to certain components of the proposed Plan) will continue between the Mirant Debtors and each of the Statutory Committees until the hearing to approve the adequacy of the Disclosure Statement. At present, the Bankruptcy Court has set the following schedule with respect to the Disclosure Statement: the First Amended Disclosure Statement is to be filed by March 25, 2005; objections to the draft Disclosure Statement are to be filed by April 1, 2005; the Second Amended Disclosure Statement is to be filed by April 15, 2005; and the Disclosure Statement adequacy hearing in the Bankruptcy Court is set for April 20, 2005.

At this time, it is not possible to accurately predict if or when the proposed Plan will be approved by the creditors and security holders and confirmed by the Bankruptcy Court, or if and when some or all of the Mirant Debtors may emerge from Bankruptcy Court protection under Chapter 11.

U.S. Competitive Environment

The power industry is one of the largest industries in the United States and has an influence on practically every aspect of the U.S. economy. Historically, the power generation industry in the United States was characterized by electric utility monopolies selling to franchised customer bases. In response to increasing customer demand for access to low-cost electricity and enhanced services, regulatory initiatives were adopted, primarily to increase wholesale and retail competition in the power industry. Following the resulting industry restructuring, merchant companies purchased plants from regulated utilities, built new capacity and began marketing to customers. At the same time, Independent System Operators (ISOs) and/or Regional Transmission Organizations (RTOs) were created to administer the new markets while maintaining system reliability. In recent years, state and federal restructuring efforts have stalled, primarily in response to the California energy crisis and financial troubles of many merchant energy companies. In addition, ISOs have begun exerting more control over market prices. The result is a blend of competitive and regulatory constructs, often different by state, under which merchant generators must compete with regulated utilities.

The substantial increase in new generation capacity that followed the restructuring of the U.S. power markets, utility capital investments to extend lives of older units, and the inability to decommission plants for reliability reasons have created a prolonged oversupply situation. We do not expect our primary markets to reach target reserve margins, approximately 15% of excess capacity over peak demand, until 2008 to 2010. The market oversupply situation, price controls during periods of high demand or local constraint, and lack of appropriate compensation for locational capacity value currently limit fixed cost recovery for merchant generators.

With the expansion of the Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) market and the ongoing development of Midwest Independent System Operators (MISO), the markets themselves continue to evolve. This evolution has changed not only the utilization of generation and transmission resources, but also the voting interests among market participants.

Recently, natural gas has been the fuel of choice for new power generation facilities for economic, operational and environmental reasons. While this trend is expected to continue, some regulated utilities are now constructing clean coal units and renewable resources, often with subsidies or under legislative mandate. These utilities enjoy a lower cost of capital than most merchants and often are able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation without relying exclusively on market clearing prices to recover their investments.

Market liquidity stabilized or improved in most regions in 2004, as compared to 2003, allowing us to economically hedge portions of our expected electricity production up to 24 months in advance, primarily through exchange-traded contracts. However, market conditions, as well as conditions specific to us, have significantly reduced our marketing and risk management activities as compared to previous years.

Business Segments

For selected financial information about our business segments and information about geographic areas, see Note 20 to our consolidated financial statements contained elsewhere in this report. See Item 2. Properties for a complete list of our assets.

North America

Overview

In our North America segment, our core business is the production and sale of electrical energy, electrical capacity (essentially the ability to produce electricity on demand) and ancillary services. Our customers in the United States are 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.

Ownership and Operations of Electricity Generation Assets

As of December 31, 2004, we owned or leased generation facilities in the United States with an aggregate generation capacity of over 14,500 MW (including our Coyote Springs facility, the sale of which closed in January 2005, and our Wrightsville facility, which we expect to sell during 2005). 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 28% baseload units, 46% intermediate units and 26% peaking units. Mirant Americas Generation owns or controls approximately two-thirds of our U.S. generating capacity. We have six facilities in our North America business unit operating under long term contracted capacity contracts. At December 31, 2004, our contracted capacity was approximately 4,325 MW pursuant to agreements with terms expiring May 2005 through December 2014.

Commercial Operations

Our commercial operations, which are conducted through our Mirant Americas Energy Marketing subsidiary, consist of fuel procurement, power dispatch, logistics, asset hedging and risk management, and optimization trading. Mirant Americas Energy Marketing conducts its business in the markets in which we have an asset presence, which enhances our ability to deliver additional value as compared to only buying fuel and selling power in the spot market.

Pursuant to agreements with our subsidiaries that own generation facilities, Mirant Americas Energy Marketing enters into transactions for the benefit of such subsidiaries pursuant to which Mirant Americas Energy Marketing procures the appropriate fuel, formulates the daily dispatch decisions and sells the electricity generated in the wholesale market for the generation facilities. Mirant Americas Energy Marketing uses dispatch models to make daily decisions regarding the quantity and the price of the power it will sell into the markets. In most markets governed by ISOs/RTOs, Mirant Americas Energy Marketing bids the energy from our generation facilities into the ISO-run day-ahead energy market. Mirant Americas Energy Marketing also sells ancillary services through the ISO markets. In real-time, Mirant Americas Energy Marketing works with the ISOs/RTOs to ensure that our generation facilities are dispatched economically to meet the reliability needs of the market. In non-ISO markets, Mirant Americas Energy Marketing conducts business through bilateral transactions, on a day-ahead basis, pursuant to which Mirant Americas Energy Marketing provides the generation facilities with firm schedules to follow.

Mirant Americas Energy Marketing enters 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, Mirant Americas Energy Marketing purchases coal from a variety of suppliers under both short-term and multi-year contracts. 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.

Mirant Americas Energy Marketing enters into transactions to economically hedge our power price exposure by selling power into the wholesale market over a variety of tenors through over-the-counter transactions, exchanges and structured transactions. Mirant Americas Energy Marketing sells both energy and energy-linked commodities, including capacity and ancillary services. Mirant Americas Energy Marketing economically hedges the energy component of gross margin through futures, forwards, swaps and options. All of Mirant Americas Energy Marketing s commercial activities are governed by our Risk Management Policy (RMP). The RMP requires that Mirant Americas Energy Marketing engage only in risk reducing activities with respect to hedging our assets.

While over-the-counter transactions make up a substantial portion of our economic hedge portfolio, Mirant Americas Energy Marketing also has a marketing function that serves as the interface between our generation facilities and customers. The marketing organization is focused on selling non-standard, structured products to customers. In addition to load following energy sales, these products typically include capacity, ancillary services, transmission losses and other energy products. Mirant Americas Energy Marketing views 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, Mirant Americas Energy Marketing is able to sell these products at a higher premium than standard products. For certain generation facilities, Mirant Americas Energy Marketing has 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.

In addition to the risk management services that Mirant Americas Energy Marketing provides to our subsidiaries that own generation facilities, Mirant Americas Energy Marketing engages in optimization trading for its own account. Mirant Americas Energy Marketing generates gross margin by taking market positions based, in part, on market and other information gathered from its relationship with our generation facilities. The optimization trading activities also are governed by the RMP, which sets forth limits on the size of trading positions and value-at-risk that Mirant Americas Energy Marketing can bear at any given time. By participating in the markets in this way, Mirant Americas Energy Marketing is better able to avoid disclosing to the markets the direction of its trading and hedging activity to the benefit of our subsidiaries that own generation facilities. We also benefit from tighter bid/offer spreads because Mirant Americas Energy Marketing is active in the markets as both a buyer and seller.

Mid-Atlantic Region

We own, directly and indirectly, or lease four generation facilities comprising 5,256 MW of generation capacity in the Mid-Atlantic region: Chalk Point, Morgantown, Dickerson and Potomac River Station. Our Mid-Atlantic facilities were acquired from Potomac Electric Power Company (PEPCO) in December 2000. These facilities consist of coal and oil fired baseload units as well as coal, gas and oil fired intermediate and peaking units in Maryland and Virginia. Our largest facility in the region, the Chalk Point facility, has two coal fired baseload units, two oil and gas fired intermediate units and seven either oil fired or oil and gas fired peaking units, totaling 2,429 MW of capacity. The next largest facility, the Morgantown facility, consists of two coal and oil fired baseload units and six oil fired peaking units, totaling 1,492 MW of capacity. The Dickerson facility has three coal fired baseload units and three peaking units, totaling 853 MW of capacity, and the Potomac River Station, a coal fired facility, has three baseload and two intermediate units, totaling 482 MW of capacity.

Power generated by our Mid-Atlantic facilities is sold into the PJM market. For a discussion of the PJM market, see Regulatory Environment U.S. Public Utility Regulation 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 also a similar TPA in place to supply PEPCO s load in Maryland, which expired in June 2004 (the Maryland TPA).

Also, 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 with Ohio Edison Company (Ohio Edison) and Panda-Brandywine L.P. (Panda) that expire in 2005 and 2021, respectively. We and PEPCO entered into a contractual arrangement (the PEPCO 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 PEPCO Back-to-Back Agreement, we are obligated to purchase power from PEPCO at prices that are significantly higher than existing market prices for power in the PJM market. On August 28, 2003, we filed a motion with the Bankruptcy Court to reject the PEPCO Back-to-Back Agreement. On December 9, 2004, we notified PEPCO and the Bankruptcy Court that we were suspending all future payments to PEPCO under the PEPCO Back-to-Back Agreement. For further information, see Item 3. Legal Proceedings.

Since the expiration of the Maryland TPA in June 2004 and the expiration of the DC TPA in January 2005, Mirant Americas Energy Marketing has been hedging the output of the Mid-Atlantic portfolio in the bilateral market as described previously. The terms for these transactions extend into 2006. In addition, Mirant Americas Energy Marketing enters into structured transactions with entities serving load in the greater Washington, D.C. area. Structured transactions are inherently more complicated than bilateral transactions, and we look to extract value over the mid-point of the market for such transactions. The terms for these transactions extend into 2006 as well.

Mirant Americas Energy Marketing also has 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.

Northeast Region

We directly own or operate generating facilities in the Northeast region consisting of approximately 3,063 MW of capacity. The Northeast region is comprised of the New York and New England sub-regions.

The Mirant New York facilities were acquired from Orange and Rockland Utilities, Inc. 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 1,675 MW of capacity. The Bowline facility is a 1,133 MW dual fueled (natural gas and oil) facility comprised of two intermediate units. The Lovett facility consists of two baseload units capable of burning coal and gas comprising a total of 348 MW and a peaking unit capable of burning gas or oil comprising 63 MW. The smaller New York plant operations include two peaking units (the Hillburn gas turbine station and the Shoemaker gas turbine station), three hydroelectric stations (Mongaup 1-4, Swinging Bridge 1-2 and Rio 1-2) and an operational interest in the Grahamsville Hydroelectric Station comprising a total of 132 MW. An expansion at the Bowline facility, a 750 MW natural gas and distillate oil fired combined cycle unit, is currently suspended.

The Mirant New England facilities, with a total capacity of 1,388 MW, were acquired from subsidiaries of Commonwealth Energy System and Eastern Utilities in December 1998. The New England generating facilities consist of the Canal station, the Kendall station, the Martha s Vineyard diesels and the Wyman Unit 4 interest. The Canal and Kendall facilities, consisting of approximately 1,109 MW and 256 MW of generating capacity, respectively, are designed to operate during periods of intermediate and peak demand, and are located in close proximity to Boston. The Kendall facility has been repowered since its acquisition and is now a natural gas 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.

Generation is sold from our Northeast assets through a combination of bilateral contracts and spot market transactions, as well as structured transactions. The Mirant New York plants participate in a market operated by the Independent System Operator of New York (NYISO). The capacity, energy and ancillary services from the Mirant New England generating units are sold into the New England Power Pool (NEPOOL) through our commercial operations. NEPOOL is administered by the ISO of New England (ISO-NE). For a discussion of the NYISO, NEPOOL and the ISO-NE, see Regulatory Environment U.S. Public Utility Regulation below.

Market fundamentals in the NYISO do not permit us to operate the Lovett facility on an economic basis as a merchant generation facility because of upcoming required environmental capital expenditures and property taxes associated with the facility. Our current plan is to retire the Lovett facility, starting with Unit 5 in 2007 and Units 3 and 4 in 2008. Market fundamentals in NEPOOL do not permit us to operate the Kendall facility on an economic basis as a merchant facility. Our plan has been to shutdown, at least temporarily, the Kendall facility from January 2006 through December 2007, with the possibility of restarting operations as early as January 2008. However, the ISO-NE has determined that a small part of the capacity of the Kendall facility is needed for reliability and has negotiated a Reliability-Must-Run (RMR) contract with respect to the Kendall facility with a term of approximately one year. We filed this contract with the Federal Energy Regulatory Commission (FERC) for RMR status under the existing tariff on October 7, 2004 and are currently waiting for FERC approval or acceptance of the agreement and the revenue requirements contained within it. We and the other parties in this proceeding are currently in settlement negotiations. We and NStar Electric & Gas Corp., the local contracting utility, have reached a preliminary agreement that, once finalized and accepted or approved by the FERC, will resolve virtually all of the issues raised in this proceeding.

Mid-Continent Region

The Mirant Mid-Continent facilities, consisting of an equity interest in roughly 2,668 MW, are located in the Midwest and Southeast markets. The Midwest facilities, which include our Sugar Creek and Mirant Zeeland facilities, consist of over 1,372 MW of generating capacity and are all natural gas fired peaking and/or intermediate units. The Southeast facilities include three facilities, Wrightsville, West Georgia and Shady Hills, with a net equity interest of 1,296 MW.

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 MISO, and AEP is a member of the PJM market. The facility is eligible to deliver energy and participate in the energy, capacity and ancillary markets of the PJM market.

The Mirant Zeeland facility, a combined cycle facility in Zeeland, Michigan, has generating capacity of 837 MW and is interconnected with the International Transmission Company, which is a member of the MISO. Both the Zeeland and Sugar Creek facilities operate under the East Central Area Reliability Coordination Agreement (ECAR).

The West Georgia facility in Thomaston, Georgia and the Shady Hills facility in Pasco County, Florida consist of gas and oil fired combustion turbines serving peak loads of approximately 605 MW and 468 MW, respectively.

The Wrightsville facility consists of gas fired intermediate/peaking units with generating capacity of 438 MW. In 2004, we mothballed this facility, pending regional recovery of power prices. In February 2005, we entered into an agreement to sell the Wrightsville facility to Arkansas Electric Cooperative Corporation (AECC), subject to Bankruptcy Court approval and certain other regulatory and third-party consents and approvals. We expect the sale of the Wrightsville facility to close in 2005.

For a discussion of MISO and ECAR, see Regulatory Environment U.S. Public Utility Regulation below.

West Region

Our West region facilities consist of a net equity interest in 3,602 MW of gas fired generating capacity in California, Oregon, Nevada and Texas.

The generating assets in California provide a total capacity of 2,347 MW and consist of the Pittsburg, Contra Costa and Potrero plants, which include facilities operating at both intermediate and peak demand levels located in, or in close proximity to, San Francisco. The Pittsburg and Contra Costa plants consist of five intermediate natural gas fired steam generating units with approximately 1,985 MW of generating capacity located approximately ten miles apart along the Sacramento/San Joaquin River Delta. The Potrero plant has one baseload natural gas fired conventional steam generating unit and three peaking distillate fueled combustion turbines with a combined capacity of 362 MW.

The majority of our California assets are subject to RMR agreements with the California Independent System Operator (CAISO). These agreements are described further under Regulatory Environment U.S. Public Utility Regulation below. The Mirant California subsidiaries currently have the largest portfolio of units which operate under RMR contracts, reflecting the fact that the location of these units is key to the electric system reliability. Contra Costa Unit 6 is not a party to an RMR agreement, and thus functions solely as a merchant facility in the CAISO. Mirant Americas Energy Marketing sells the output of Contra Costa Unit 6 into the market through bilateral transactions with utilities and other merchant players.

In October 2004, the CAISO notified us that the RMR contract for Pittsburg Unit 7 would not be renewed for 2005. On January 3, 2005, Mirant Americas Energy Marketing announced that it was seeking proposals for a one-, two- or three-year tolling arrangement for Pittsburg Unit 7 and Contra Costa Unit 6. We received bids on January 28, 2005, and we are in the process of evaluating these bids at this time. If this request for proposal does not result in an acceptable contract for Pittsburg Unit 7, we intend to retire Pittsburg Unit 7, consisting of 682 MW, by the middle of 2005, due to new nitrogen oxide (NOx) emissions standards that would require significant capital and operating and maintenance expenditures.

Coyote Springs is a 280 MW intermediate combined-cycle gas fired plant, located in Boardman, Oregon, that began commercial operations in July 2003. In October 2004, we entered into an agreement to sell our 50% interest in Coyote Springs to Avista Utilities, subject to Bankruptcy Court and the FERC approval. The Bankruptcy Court and the FERC approved the sale in December 2004 and the sale was completed for $63 million in January 2005.

The Apex generating facility, a 500 MW intermediate gas combined-cycle facility located near Las Vegas, Nevada, was developed by us and began commercial operations in May 2003.

We operate 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 (combined cycle unit) with a capacity of 230 MW that is available to serve baseload and intermediate demand. Additionally, Bosque Units 1 and 2 are gas fired peakers with a capacity of 154 MW each. 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.

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 U.S. Public Utility Regulation below.

International

Through various subsidiaries, we own or control under operating agreements various generation, transmission and distribution operations in the Philippines and the Caribbean. A complete list of our international properties is contained in Item 2. Properties.

Philippines

We, indirectly through our Philippine subsidiaries, have ownership, leasehold or similar interests in nine generating facilities in the Philippines. As of December 31, 2004, our net ownership interest in the generating capacity of these facilities was approximately 2,300 MW. Over 80% of the generation capacity in the Philippines 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, Navotas II 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 associate, 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. In addition to the energy conversion agreements with NPC, our Sual and Pagbilao subsidiaries have joint marketing agreements with NPC for excess capacity of 218 MW and 35 MW, respectively. Currently, electricity from the excess capacity of our Sual facility is provided to select markets such as economic zones, industries and private electric distribution companies and cooperatives.

Under the energy conversion agreements, our respective subsidiaries and associates receive both fixed capacity fees and variable energy fees. Currently, approximately 90% of our revenues with respect to our Philippine operations come from fixed capacity charges under long-term contracts that are paid without regard to the dispatch level of the facility. Nearly all of our capacity fees are denominated in U.S. dollars. Energy 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 are 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 agreements for our Navotas II, Sual, Pagbilao and Ilijan facilities expire in July 2005, October 2024, August 2025 and January 2022, respectively.

Our larger Philippine projects have been granted preferred or pioneer status that, among other things, has qualified them for income tax holiday incentives of three to six years. The income tax holiday incentive expired in June 2002 for our Pagbilao facility and will expire in October 2005 and January 2008 for our Sual and Ilijan facilities, respectively. The amount of benefit from these holiday incentives is $54 million, $50 million, and $69 million for 2004, 2003, and 2002, respectively.

Deregulation and Privatization

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 independent power producers (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 would occur within three years from its effective date. 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. As of December 2004, most of these changes have started to occur but are considerably behind the schedule set by the Philippine Department of Energy.

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. As of December 2004, 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 are not assignable without consent. We are in continuing discussions with NPC and PSALM on a proposal to add PSALM as an additional obligor under its existing IPP contracts. Additionally, the Philippine government issued performance undertakings to guarantee the performance of NPC s obligations under certain energy conversion agreements.

Philippine IPP Review

Pursuant to EPIRA, a governmental inter-agency committee reviewed all IPP contracts and reported that some contracts had legal or financial issues requiring further review or action, including contracts with our subsidiaries. Subsequently, we, along with PSALM, the Philippine Department of Energy and the Philippine Department of Justice entered into a letter of agreement establishing a general framework (the General Framework Agreement) for resolving all outstanding issues raised by the committee about IPP contracts with our subsidiaries.

In March 2003, the conditions precedent for our Sual and Pagbilao components of the General Framework Agreement were satisfied and the implementation agreements relating to both became effective. As a result of the General Framework Agreement, the original energy conversion agreements for our Sual and Pagbilao facilities remain intact and are reaffirmed with no resultant material financial impact.

Caribbean

Our net ownership interest in the generating capacity of our Caribbean plants is approximately 1,000 MW.

Grand Bahama Power Company (Grand Bahama Power)

We own a 55.4% interest in Grand Bahama Power, an integrated electric utility company that generates, transmits, distributes and sells electricity on Grand Bahama Island. Grand Bahama Power has the exclusive right and obligation to supply electric power to the residential, commercial and industrial customers on Grand Bahama Island. Grand Bahama Power s rates are approved 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 plants located on the island of Trinidad. The electricity produced by PowerGen is provided to the Trinidad and Tobago Electricity Commission (T&T EC), 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&T EC, which expires in 2009 and is unconditionally guaranteed by the government of Trinidad and Tobago. Under this contract, the fuel is provided by the T&T EC.

In response to a September 3, 2004 request for proposals issued by National Gas Company of Trinidad and Tobago Limited (NGC), 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) and T&T EC. The request for proposals contemplates a need of between 200 MW and 250 MW for T&T EC and possibly a further need of between 400 MW and 540 MW for NEC with commercial operations dates between the third quarter of 2006 and March 2008. PowerGen will likely have definite resolution related to this bid by mid-2005.

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 that expires in 2021 and that provides JPS with the exclusive right to sell power in Jamaica. JPS has installed generation capacity of 600 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 540,000 residential, commercial and industrial customers in Jamaica. At present, JPS is regulated by the Office of Utilities and Regulation under a price cap model with rate cases held every five years and with interim adjustments indexed to inflation and foreign exchange movements.

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.

Aqualectra

We own a $40 million convertible preferred equity interest in Aqualectra, an integrated water and electric company in Curacao, Netherlands Antilles, owned and operated 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. Aqualectra has a call option and we have a put option, both of which became exercisable for the three-year period beginning on December 19, 2004. We also have an option to convert our convertible preferred equity interest in Aqualectra to common shares during the same three-year period beginning December 19, 2004.

Regulatory Environment

U.S. Public Utility Regulation

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 (the Federal Power Act), over sales of electricity at wholesale and the transmission of electricity in interstate commerce. A Mirant subsidiary 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 Mirant 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, for which blanket authority has been granted. In addition, under the Natural Gas Act (NGA), the FERC has limited jurisdiction over certain sales for resale of natural gas, but does not regulate the prices received by the Mirant subsidiary that markets natural gas.

The FERC has authorized the public utility Mirant subsidiaries to sell energy and capacity at wholesale market-based rates and has authorized some of the public utility Mirant subsidiaries to sell certain ancillary services at wholesale market-based rates. The majority of the output of the generation facilities owned by Mirant s public utility subsidiaries in the United States 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. 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 our subsidiary 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, the Mirant 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 a Mirant subsidiary, it would no longer be able to make certain sales of natural gas.

In an effort to promote greater competition in wholesale electricity markets, the FERC has encouraged the formation of ISOs and RTOs. In those 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. The majority of our facilities operate in these ISO/RTO regions.

We are not currently subject to the Public Utility Holding Company Act of 1935, as amended (PUHCA), and do not anticipate becoming so unless we acquire the securities of a public utility company or public utility facility that does not qualify as an exempt wholesale generator, a foreign utility company, or a qualifying small power production or cogeneration facility. Currently, our subsidiaries owning generation in the United States are exempt wholesale generators under PUHCA, and all of our subsidiaries owning generation outside the United States are either foreign utility companies or exempt wholesale generators.

At the state and local levels, regulatory authorities have historically 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. Our subsidiaries that sell at the retail level in states that have a retail access program 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 assets 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 and performs transmission planning for the region. To account for transmission congestion and losses, PJM calculates electricity prices using a locational-based marginal pricing model and dispatches electricity on a security constrained least cost basis. On January 24, 2005, the FERC issued an order changing PJM s mitigation rules for frequently mitigated units (those mitigated in excess of 80% of annual running hours), as well as the retirement policy rules. The revised policy provides some opportunity for increased compensation for frequently mitigated units. Under the old rules, such units were restricted to bidding variable costs plus 10% when a transmission constraint caused the unit to be selected out of economic merit order. Under the new rules, the restriction is variable costs plus $40/megawatt hour (MWh). Units mitigated less than 80% of the time remain under the old cost plus 10% policy. PJM also proposed a revised generation retirement policy that sets forth a process by which PJM will address a request by a generation owner to deactivate a unit, determine whether established reliability criteria would be violated if the unit were deactivated, and provide compensation to the generation owner when a unit proposed for deactivation is required to continue operating for reliability. This proposal was also approved. Both changes are currently effective, although possibly subject to revision via requests for rehearing. PJM is also developing a redesign of its capacity obligations, referred to as a Reliability Pricing Model (RPM), and the RPM is anticipated to be filed at the FERC in late March 2005. If filed in a form resembling stakeholder discussions to date, and ultimately approved by the FERC, this proposal would also provide some opportunity for an improved revenue stream for Mirant-owned capacity. However, the FERC s response to these issues and the final impact, if any, on our facilities cannot be determined at this time.

PJM has greatly expanded its system over the last two years with the addition of the service areas of Allegheny Power, Commonwealth Edison, AEP, Duquesne Light and Dayton Power & Light (DP&L) and the anticipated addition of Dominion-Virginia Power in 2005. In the fall of 2004, PJM completed its integration of AEP and DP&L into the PJM RTO. For purposes of determining deliverability to the unforced capacity market (UCAP market), AEP and DP&L were deemed to be capable of providing capacity to all areas of PJM. This effectively provided the same comparability of delivery for a generator in western Ohio to deliver capacity to the PEPCO zone where our assets are located. The deliverability standard and the additional capacity that the new entrants are now capable of providing to the UCAP market in PJM has severely depressed forward pricing for capacity. PJM has proposed a new RPM that will provide for recognition of locational deliverability zones. The model proposes a phase in to locational zones over a four-year period. In addition, PJM and MISO have been directed by the FERC to establish a common and seamless market, an effort that is largely dependent upon MISO s ability to first establish and operate its markets.

Northeast Region Our New York plants participate in a market controlled by NYISO, which replaced the New York Power Pool (NYPP). NYISO provides statewide transmission service under a single tariff and interfaces with neighboring market control areas. To account for transmission congestion and losses, NYISO calculates energy prices using a locational-based marginal pricing model that is similar to that used in the PJM and ISO-NE. NYISO also administers a spot market for energy, as well as markets for installed capacity, operating reserves and regulation service. 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. On January 14, 2005, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded the FERC s orders approving the AMP. The AMP provisions of the NYISO s tariff remain in effect pending further proceedings. 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 for three locational zones: New York City, Long Island and the rest of New York. Our facilities operate outside of New York City and Long Island. The demand curve is derived for each of the three zones by setting the price of installed capacity for 118% of peak load (peak load plus an 18% reserve margin) at the assumed price for a new generating plant to serve peak demand (new entrant) and then sloping the demand curve for installed capacity downward to reflect additional amounts of capacity beyond the 118%. The FERC approved the new entrant price for use from the summer of 2003 to the spring of 2005, and required NYISO to file three proposed new entrant prices that would be applicable from the summer of 2005 through the spring of 2008. On January 7, 2005, NYISO filed revisions to its services tariff to define the demand curves for capability years 2005/2006, 2006/2007 and 2007/2008. A FERC order is expected on the 2005 through 2008 demand curves in March 2005. The FERC s 2003 order approving the existing demand curves has been appealed by a trade association to the U.S. Court of Appeals for the D.C. Circuit.

Our New England plants also participate in a market administered by ISO-NE, under contract to NEPOOL, which is a voluntary association of electric utilities and other market participants in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. The FERC has approved a RTO for the New England region (RTO-NE), which assumed responsibility for the operation of transmission systems and administration and settlement of the wholesale electric energy, capacity and ancillary services markets on February 1, 2005. ISO-NE utilizes a locational marginal pricing model, with a price mitigation method similar to NYISO s AMP. In 2004, the FERC approved a locational installed capacity market for ISO-NE based on the demand curve concept also used by NYISO, to be implemented in January 2006. A hearing on the demand curve parameters was held in late February and early March and a FERC order on these proposals is expected in mid to late-2005.

Mid-Continent Region Our Mid-Continent plants are located in the Midwest and Southeast markets. In the Midwest markets, our plants participate in a market to be administered by MISO. The FERC approved the formation of MISO in 2001, and it currently administers transmission operations. MISO intends to operate energy markets similar to those operated by PJM and has received FERC approval to commence operating energy markets on March 1, 2005. However, due to a desire to test thoroughly before implementation, MISO has voluntarily elected to delay actual implementation until April 1, 2005. MISO plans to use locational marginal pricing for energy and associated financial transmission rights so that market participants may manage the risks associated with moving energy from generation sources to load. The market plan also includes both a day-ahead energy market based on firm financial commitments to provide energy and a real-time market for physical supply and demand. MISO proposes to implement a capacity market by June 1, 2006, but has not yet identified a specific capacity market design. MISO also proposes to implement mitigation rules similar to those of NYISO, but will likely not implement an automatic price cap. While tangible progress continues to be made toward actual implementation, we still cannot provide assurance regarding whether or when MISO will commence operation of its new market or what the impact on our earnings could be. The Sugar Creek facility is interconnected to both MISO and PJM, through Cinergy and AEP s transmission system, and can sell into either market (though 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 from our facilities 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 West plants are located in the Western Interconnection and the ERCOT market in Texas. California accounts for roughly 40% of the energy consumption in the Western Interconnection. Approximately 75% of California s demand is served from facilities in the CAISO control area, which includes our California facilities. The CAISO schedules transmission transactions, arranges for necessary ancillary services and administers a real-time balancing energy market. The CAISO has proposed changes to its market design to more closely mirror the eastern RTO markets. The market redesign has been delayed several times, with full implementation now expected in 2007 or 2008. The California Public Utility Commission (CPUC) has taken the lead role for establishing capacity requirements in California and has ordered California s load-serving entities to meet specific load and reserve requirements beginning in the summer of 2006. The CAISO has not proposed a capacity market mechanism in its market redesign.

The majority of our assets in California are subject to RMR agreements 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 agreements, 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 assets 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 in RMR payments. For these generation assets, only a percentage of the Annual Requirement, as approved by the FERC, can be recovered through RMR payments, whereas RMR Contract Condition 2 Units recover 100%. The contracts require yearly filings for FERC approval of the Annual Requirement for the following calendar year.

The CAISO imposes a $250/MWh cap on prices for energy and capacity and has implemented an AMP similar to that used by NYISO. Owners of non-hydroelectric generation in California, including certain of our facilities, must offer power in the CAISO s spot markets if the output is not scheduled for delivery within the hour. For the remaining units located outside of California, but within the Western Interconnection, there is no single entity responsible for a centralized bid-based market. Outside of California, the primary markets in the West today are bilateral and adhere to the reliability standards of the Western Electricity Coordinating Council (WECC). Although we are active participants in initiatives to establish new ISOs or RTOs in the West, we can neither predict when, nor if, such entities will emerge nor if market developments will have a positive or negative impact on future earnings from our Western assets.

Our Texas plants participate in a market administered by the ERCOT ISO, which manages a major portion of the state s electric power grid. ERCOT ISO oversees competitive wholesale and retail markets resulting from electricity restructuring in Texas and protects the overall reliability of the ERCOT grid. ERCOT ISO, 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. To improve congestion management, the PUCT recently established a rulemaking proceeding on wholesale market design issues that will focus on adding a congestion management mechanism based on locational pricing, similar to that used in PJM, and a day-ahead market. A revised market design is expected to be in place by 2005 but, as with other evolving market structures, we cannot provide assurance as to when the enhancements will be completed and implemented, or what the impact on earnings in the ERCOT market will be.

Environmental Regulation

United States

Air Emissions Regulations: Our business is subject to extensive environmental regulation by federal, state and local authorities, which requires continuous compliance with regulations and conditions established by their operating permits. Our most significant environmental requirements in the United States arise under the federal Clean Air Act of 1990, as amended (the Clean Air Act), and similar state laws. Under the Clean Air Act, we are required to comply with a broad range of requirements and restrictions 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 U.S. Environmental Protection Agency (EPA) as not achieving certain federal ambient air quality standards. The regulatory classification of these areas subjects our operations in these areas to more stringent air regulation requirements, potentially including, in some cases, required emission reductions. Also, states are required by Section 185 of the Clean Air Act to impose additional fees for air emissions from major sources in areas that are classified as severe non-attainment for ozone and that fail to meet the attainment deadline. For example, the Virginia and

Maryland suburbs of Washington D.C. are part of the Washington, D.C. non-attainment area and currently are classified as severe non-attainment for ozone, applying a one-hour ozone standard. The EPA has designated this area as moderate non-attainment applying a new eight-hour standard and has indicated that it will rescind the one-hour ozone standard in June 2005. If it does not rescind the one-hour standard and the November 2005 attainment deadline under the one hour standard is not met, Section 185 of the Clean Air Act would require Virginia and Maryland to begin imposing additional fees on major sources of ozone beginning in 2006. The formula for determining this fee has not been finally established, but is likely to be a significant cost for our Mid-Atlantic plants. On September 27, 2004, we entered into a conditional consent decree resolving an enforcement proceeding with the state of Virginia and EPA. The consent decree was also entered into by the state of Maryland and the Department of Justice (the DOJ) on behalf of the EPA. The consent decree creates annual and ozone season caps on NOx emissions, provides for certain additional pollution controls, supplemental environmental projects to be done at the Potomac River plant and a $500,000 fine. Approvals by the Federal District Court in Alexandria and the Bankruptcy Court are being sought.

In the future, we anticipate increased regulation of generation facilities under the Clean Air Act and applicable state laws and regulations concerning air quality. The EPA and several states in which we operate are in the process of enacting more stringent air quality regulatory requirements.

For example, the EPA promulgated regulations (referred to as the NOx SIP Call), which establish emission cap and trade programs for NOx emissions from electric generating units in most of the Eastern states. These programs were implemented beginning May 2003 in the Northeast and May 2004 in the rest of the region. Under these regulations, a plant receives an allocation of NOx emission allowances, and if a plant exceeds its allocated allowances, the plant must purchase additional, unused allowances from other regulated plants or reduce emissions, which could require the installation of emission controls. Our plants in Maryland, New York and Massachusetts complied with similar state and regional NOx emission cap and trade programs from 1999 to 2002, which has been superseded by the EPA NOx cap and trade program. Some of our plants in these states are required to purchase additional NOx allowances to cover their emissions and maintain compliance. The cost of these allowances may increase in future years and may result in some of our plants reducing NOx emissions through additional controls, the cost of which could be significant but would be offset in part by the avoided cost of purchasing NOx allowances to operate the plant.

The EPA also has promulgated regulations that establish emission cap and trade programs for sulfur dioxide (SO_2) emissions (the Acid Rain Program) from electric generating units in the United States. This Acid Rain Program was implemented in two phases. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 Eastern and Midwestern states. Phase II, which began in 2000, tightened the annual emissions limits imposed on Phase I plants and also set restrictions on smaller, cleaner plants fired by coal, oil and gas encompassing over 2,000 units in all. The Acid Rain Program affects existing utility units serving generators with an output capacity of greater than 25 MW and all new utility units. The Acid Rain Program represents a dramatic departure from traditional command and control regulatory methods, which establish specific, inflexible emissions limitations with which all affected sources must comply. Instead, the Acid Rain Program introduces an allowance trading system that harnesses the incentives of the free market to reduce pollution. Under this system, affected utility units were allocated allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO_2 during or after a specified year. Allowances may be bought, sold or banked. Anyone may acquire allowances and participate in the trading system. The Acid Rain Program set a permanent ceiling (or cap) of 8.95 million allowances for total annual allowance allocations to utilities. All of our facilities are in compliance with the requirements of the Acid Rain Program. Some of our plants have surplus allowances and some are required to purchase additional SO_2 allowances to cover their emissions and maintain compliance. The costs of these allowances may increase in future years and may result in some of our plants reducing SO_2 emissions through additional controls, the cost of which could be significant but would be offset in part by the avoided cost of purchasing SO2 allowances to operate the plant.

The Acid Rain Program also has a NOx emission reduction program. This program only affects coal fired units and also was implemented in a two-phase approach in 1995 and 2000. This program is not a cap and trade program but identifies specific emission rates and/or control technology requirements. We have installed the NOx control technology and/or are meeting applicable emission rates. All our coal units are in compliance with requirements of the Acid Rain Program s NOx emission reduction program. We foresee no additional expense to comply with this program.

The EPA has proposed regulations to govern mercury air emissions from coal fired power plants. This proposal offers alternate regulatory approaches, which include a cap and trade program that would go into effect in January 2010 and a maximum achievable control technology standard (unit specific emission standard) that would go into effect in December 2007, which may be extended by the EPA to December 2008. The mercury regulations are likely to require significant emission reductions from coal fired power plants. This rulemaking also proposes new regulations governing nickel air emissions from oil fired power plants, which would either go into effect in December 2007, with a possible one-year extension by the EPA to December 2008, or go into effect January 2010. The cost to comply with such requirements could be significant.

During the course of this decade, the EPA will be implementing new, more stringent ozone and particulate matter ambient air quality standards. It will also address regional haze visibility issues, which will result in new regulations that will likely require further emission reductions from power plants, along with other emission sources such as vehicles. To implement these air quality standards, the EPA promulgated the Clean Air Interstate Rule (CAIR) on March 10, 2005. The CAIR 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 power plants. These cap and trade programs will be implemented in two phases, with the first phase going into effect in 2009 and more stringent caps going into effect in 2015.

These future mercury and nickel regulations and the CAIR would increase compliance costs for our operations and would likely require emission reductions from some of our power plants, which would necessitate significant expenditures on emission controls or have other impacts on operations. These rulemakings are likely to be finalized in early 2005. Until the final regulations are promulgated, we cannot predict whether the regulations will have a material adverse effect on our financial condition, cash flows and results of operations.

In addition to implementation of statutes already in existence, there are additional environmental requirements under strong consideration by the federal and various state legislatures. The Bush Administration has submitted Clean Air Act multi-emission reform legislation to Congress, which would promulgate a new emissions cap and trade program for NOx, SO2 and mercury emissions from power plants. This legislation would require overall reductions in these pollutants from national power plant emissions of approximately 50-75% phased in during the 2008 - 2016 timeframe, which is similar to the types of overall reductions likely to be required under the future EPA regulations discussed above. Other more stringent multi-emission reform legislation also has been proposed in Congress by some lawmakers. There are many political challenges to the passage of multi-emission reform legislation through Congress, and it is unclear whether any of this legislation ultimately will be enacted into law.

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 plants and operations. We expect to incur additional compliance costs as a result of these additional state requirements, which could include significant expenditures on emission controls or have other impacts on our operations.

For example, the Commonwealth of Massachusetts has finalized regulations to further reduce NOx and SO2 emissions from certain power plants and to regulate carbon dioxide and mercury emissions for the first time. Mercury emission reductions will be required exclusively from coal fired facilities. These regulations, which become effective in the 2004-2008 timeframe, will apply to our oil fired Canal plant in the state, will increase our operating costs and will likely necessitate the installation of additional emission control technology.

Another example is in the San Francisco Bay Area, where we own power plants. NOx emission standards have become increasingly stringent on a specified schedule over a several year period, culminating in 2005. We will continue to apply our NOx implementation plan for these plants, which includes the installation of emission controls as well as the gradual curtailment and phasing out of one or more of our higher NOx emitting units.

Additionally, in 2003, the State of New York finalized air regulations that significantly reduced allowances for NOx and SO2 emissions from power plants through a state emissions cap and allowance-trading program, which will become effective during the 2004-2008 timeframe. This regulation will necessitate that we act on one, or a combination of the following options: install emission controls at some of our units to reduce emissions, purchase additional state NOx and SO2 allowances under the regulatory program or reduce the number of hours that units operate. We expect to incur additional compliance costs as a result of these additional state requirements, which could include significant expenditures on emission controls or have other impacts on operations.

These examples are illustrative but not a complete discussion of the additional federal and state air quality laws and regulations that we expect to become applicable to our plants and operations in the coming years. We will continue to evaluate these requirements and attempt to develop compliance plans that enable us to appropriately manage the costs and impacts.

Other Environmental Regulations: There are other environmental laws in the United States, in addition to air quality laws, that also affect our operations. We are required under the Clean Water Act to comply with effluent and intake requirements, technological controls and operating practices. Our wastewater discharges are permitted 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. For example, in 2004, the EPA issued a new rule that imposes more stringent standards on the cooling water intakes for power plants. We expect to incur additional compliance costs to comply with this new rule.

Our facilities also are subject to several waste management laws and regulations in the United States. The Resource Conservation and Recycling Act sets forth very 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 our 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, known as the Superfund, establishes a framework for dealing with the cleanup of contaminated sites. Many states have enacted state superfund statutes. Some of the landfills that are used for the disposal of ash may be subject to these regulations.

Current Enforcement Issues: In 1999, the DOJ on behalf of the EPA commenced enforcement actions against the power generation industry for alleged violations of the new source review regulations promulgated under the Clean Air Act (NSR), which require permitting and other requirements for maintenance, repairs and replacement work on plants. This action ultimately came to encompass the vast majority of coal fired plants, with litigation against many of the largest utilities. These enforcement actions concern maintenance, repair and replacement work (MRR work) at power plants that the EPA alleges violated permitting and other requirements under the NSR law, which, among other things, could require the installation of emission controls at a significant cost. As a general proposition, the power generation industry disagrees with the EPA s positions in the lawsuits and contends that this work was routine and exempt from the permit requirement. In 2003, there were two trial court decisions that most directly addressed the issue of whether certain MRR work triggers permitting and other NSR requirements, and the courts are split on the issue.

To date, no lawsuits or administrative actions alleging similar NSR violations have been brought by the EPA against us or our power plants. However, in 2001 the EPA requested information concerning some of our Mid-Atlantic plants covering a time period that predates our ownership and leases.

In addition, there were two regulatory developments concerning NSR in 2003 that will affect the EPA s application of NSR in the future and, potentially, the NSR enforcement actions. In a new NSR rule, the EPA promulgated an exemption from NSR for MRR work that does not exceed 20% of the replacement value of a unit, which is generally consistent with power plant MRR work practices. In the rulemaking, the EPA also announced a policy of interpreting NSR in a way that seems generally consistent with reasonable industry practices. The new rule is being challenged in federal court and has been stayed pending judicial review, and, most recently, the EPA has announced that it is reconsidering the rule. It is unclear whether this rule will be changed or what effect these developments will have on the EPA s NSR enforcement action.

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 plant prior to its acquisition by us. On June 11, 2003, we and the State of New York entered into a consent decree that releases us from all potential liability for matters addressed in the NOV previously issued by the State to the prior owner. The consent decree also releases us for any other potential violation of NSR or related New York air laws prior to and through the date of entry of the consent decree by the court.

Under the decree we committed to install comprehensive emissions reduction technology on Lovett s two coal-fired units by 2007 to 2008. The consent decree also allows us to shut down or convert one of the units to burning natural gas only rather than install the prescribed emission controls on the unit.

We cannot provide assurance that lawsuits or other administrative actions against the power plants under NSR will not be filed or taken in the future. If an action is filed against us or our power plants and we are judged to not be in compliance, we could be required to make substantial expenditures to bring the power plants into compliance, which could have a material adverse effect on our financial condition, results of operations or cash flows.

International

Some 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, other countries in which our subsidiaries have operations, such as Trinidad and Jamaica, are developing increased environmental regulation of many industrial activities, including increased regulation of air quality, water quality and solid waste management.

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 (GHGs), one of which is carbon dioxide emitted from the combustion of fossil fuels by sources such as vehicles and power plants. Recently, the European Union and certain developed countries ratified the Kyoto Protocol, an international treaty regulating GHGs, and it became effective on February 16, 2005. The current U.S. administration is opposed to the treaty, and the United States has not ratified, and is not expected to ratify, the treaty. Therefore, the treaty does not bind the United States. None of the countries in which we or our subsidiaries presently own or operate power plants has any binding obligations under the treaty. The Commonwealth of Massachusetts has promulgated carbon dioxide (CO_2) emission standards for certain power plants, as discussed above in this section. 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, 2004, our corporate offices and majority owned or controlled subsidiaries employed approximately 4,700 persons. This number includes approximately 550 employees in the corporate and North America headquarters in Atlanta, approximately 1,350 employees at operating facilities in the United States and approximately 2,800 international employees. Approximately 900 of our domestic employees are subject to collective bargaining agreements with one of the following unions: International Brotherhood of Electrical Workers, Utilities Workers of America or United Steel Workers.

Union	Location	Number of Employees Covered	Contract Expiration Date
International Brotherhood of Electrical Workers Local 1900	Maryland and Virginia	515	6/1/2010
International Brotherhood of Electrical Workers Local 503	New York	150	6/1/2008
International Brotherhood of Electrical Workers Local 1245	California	140	10/31/2005
Utility Workers of America Local 369	Cambridge, Massachusetts	30	2/28/2009
Utility Workers of America Local 480	Sandwich, Massachusetts	50	5/1/2006
United Steel Workers Local 12502	Indiana and Michigan	25	1/1/2007
Oilfield Workers Trade Union	Trinidad	325	12/31/2005
The Senior Staff Association	Trinidad	35	2/28/2006
Bahamas Industrial Engineers, Managerial, and Supervisory Union(1)	Grand Bahama	33	1/1/2005
Commonwealth Electrical Workers Union(2)	Grand Bahama	131	3/31/2005
Jamaica Public Service Managers Association(3)	Jamaica	190	11/30/2004
Union of Clerical Administrative & Supervisory Employees; National Workers Union; Bustamante Industrial Trade Union(3)	Jamaica	1,130	12/31/2004

(1) Neither side has submitted a contract proposal yet. This is not uncommon and there is no work stoppage expected.

(2) Management is currently communicating with the union to agree on a start date for negotiations. Overall, the industrial climate is stable.

(3) All unions in Jamaica were requested in writing to submit claims (proposals) prior to the expiration of the contracts. To date, only the UCASE union has submitted a claim that is being reviewed. Negotiations have not begun, as management would prefer to receive all claims prior to initiation of talks. 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 2. *Properties*

The following properties were owned or leased as of December 31, 2004:

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)**
NORTH AMERICA						
West Region:						
Mirant California	California	Peaking/Intermediate	Natural Gas	100	2,347	2,347
Mirant Texas	Texas	Peaking/Baseload	Natural Gas	100	538	538
Apex	Nevada	Intermediate	Natural Gas	100	500	500
Coyote Springs(3)(4)	Oregon	Intermediate	Natural Gas/Steam	50	280	140
Mirant Wichita Falls	Texas	Peaking	Natural Gas	100	77	77
Subtotal					3,742	3,602
Northeast Region:						
Mirant New England(5)	Massachusetts	Intermediate/Peaking	Natural Gas/Oil	100	1,993	1,388
Mirant New York	New York	Intermediate/Peaking/Baseload	Natural Gas/Hydro/Coal/Oil	100	1,675	1,675
Subtotal					3,668	3,063
Mid-Atlantic Region:						
Mirant Mid-Atlantic	Maryland	Intermediate/Peaking/Baseload	NaturalGas/Coal/Oil	100	4,252	4,252
Mirant Peaker and Mirant Potomac River	Maryland/Virginia	Intermediate/Peaking/Baseload	NaturalGas/Coal/Oil	100	1,004	1,004
Subtotal					5,256	5,256
Mid-Continent Region:						
Mirant Zeeland	Michigan	Peaking/Intermediate	Natural Gas	100	837	837
West Georgia(3)	Georgia	Peaking	Natural Gas/Oil	100	605	605
Sugar Creek	Indiana	Peaking	Natural Gas	100	535	535
Shady Hills(3)	Florida	Peaking	Natural Gas	100	468	468
Wrightsville(6)	Arkansas	Peaking/Intermediate	Natural Gas	51	438	223
Subtotal					2,883	2,668
North America Total					15,549	14,589
INTERNATIONAL						
Philippines:						
Sual(7)	Philippines	Baseload	Coal	94.9	1,218	1,155
Ilijan						