EDISON MISSION ENERGY
Form S-4
September 10, 2007

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As filed with the Securities and Exchange Commission on September 10, 2007

Registration No. [ ]

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-4

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

Edison Mission Energy

(Exact name of registrant as specified in its charter)

Delaware	**4911**	**95-4031807**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

18101 Von Karman Avenue, Suite 1700
Irvine, California 92612
(949) 752-5588

(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Steven D. Eisenberg, Esq.
Edison Mission Energy
18101 Von Karman Avenue, Suite 1700
Irvine, California 92612
(949) 752-5588

(Name, address, including zip code, and telephone number, including area code, of agent for service)

With copies to:

Robert M. Chilstrom, Esq.
Harold F. Moore, Esq.
Skadden, Arps, Slate, Meagher & Flom LLP
Four Times Square
New York, New York 10036-6522
(212) 735-3000

Approximate date of commencement of proposed sale to the public: As soon as practicable after this registration statement becomes effective.

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Proposed Maximum Offering Price per Security(1)	Proposed Maximum Aggregate Offering Price(1)	Amount of Registration Fee
7.00% Senior Notes due May 15, 2017	$ 1,200,000,000	100%	$ 1,200,000,000	$ 36,840
7.20% Senior Notes due May 15, 2019	$ 800,000,000	100%	$ 800,000,000	$ 24,560
7.625% Senior Notes due May 15, 2027	$ 700,000,000	100%	$ 700,000,000	$ 21,490

(1) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(f) under the Securities Act of 1933.

The Registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to the said Section 8(a), may determine.

Subject to completion, dated September 10, 2007.

PROSPECTUS

Edison Mission Energy

Offer to exchange $1,200,000,000 aggregate principal amount of 7.00% Senior Notes due May 15, 2017 (CUSIPs 281023 AS 0, U27811 AE 5 and 281023 AT 8) for $1,200,000,000 7.00% Senior Notes due May 15, 2017 which have been registered under the Securities Act of 1933, as amended, $800,000,000 aggregate principal amount of 7.20% Senior Notes due May 15, 2019 (CUSIPs 281023 AV 3, U27811 AF 2 and 281023 AW 1) for $800,000,000 7.20% Senior Notes due May 15, 2019 which have been registered under the Securities Act of 1933, as amended, and $700,000,000 aggregate principal amount of 7.625% Senior Notes due May 15, 2027 (CUSIPs 281023 AY 7, U27811 AG 0, 281023 AZ 4) for $700,000,000 7.625% Senior Notes due May 15, 2027 which have been registered under the Securities Act of 1933, as amended

The exchange offer will expire at 5:00 p.m., New York City time, on ____________, 2007, unless extended.

Terms of the exchange offer:

The new notes are being registered with the Securities and Exchange Commission and are being offered in exchange for the old notes that previously were issued in an offering exempt from the Securities and Exchange Commission's registration requirements.

The terms of the exchange offer are summarized below and more fully described in this prospectus.

We will exchange the new notes to be issued for all outstanding old notes that are validly tendered and not withdrawn pursuant to the exchange offer.

You may withdraw tenders of old notes at any time prior to the expiration of the exchange offer.

The terms of the new notes are substantially identical to those of the old notes, except that the transfer restrictions and registration rights relating to the old notes will not apply to the new notes.

The exchange of old notes for new notes will not be a taxable transaction for United States federal income tax purposes, but you should see the discussion under the heading "Material U.S. Federal Income Tax Consequences."

We will not receive any cash proceeds from the exchange offer.

We issued the old notes in a transaction not requiring registration under the Securities Act of 1933, as amended, and as a result, their transfer is restricted. We are making the exchange offer to satisfy your registration rights, as a holder of the old notes.

See "Risk Factors" beginning on page 13 for a discussion of certain risks that you should consider prior to tendering your outstanding old notes for exchange.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy of accuracy of this prospectus. Any representation to the contrary is a criminal offense.

Prospectus dated ____________, 2007

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement on Form S-4 under the Securities Act of 1933, as amended, (the "Securities Act") that we filed with the Securities and Exchange Commission (the "SEC"). You should rely only on the information contained in this prospectus or to which we have referred you. We have not authorized anyone to provide you with information that is different. We are not making an offer of these securities in any state where the offer is not permitted. The information in this prospectus may only be accurate on the date of this prospectus.

This prospectus contains summaries, believed to be accurate, of some of the terms of specific documents, but reference is made to the actual documents, copies of which will be made available upon request, for the complete information contained in those documents. All summaries are qualified in their entirety by this reference.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports and other information with the SEC. You may read and copy any document that we file at the public reference rooms of the SEC at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the public reference rooms by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site at http://www.sec.gov, from which you can access our filings. Any statement made in this prospectus concerning any document filed with the SEC is not necessarily complete, and reference is made to the copy of the document filed.

This prospectus incorporates important business and financial information about us from documents that we have filed with the SEC but have not included in or delivered with this prospectus. We will provide you with copies of this information, without charge, upon written or oral request to:

Edison Mission Energy
18101 Von Karman Avenue, Suite 1700
Irvine, California 92612
(949) 752-5588
Attention: General Counsel

To obtain timely delivery of requested documents before the expiration of the exchange offer, you must request them no later than ____________, 2007, which is five business days before the exchange offer expires.

FORWARD-LOOKING STATEMENTS

This prospectus contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements reflect our current expectations and projections about future events based on our knowledge of present facts and circumstances as of the date of this prospectus and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by us that is incorporated in this prospectus, or that refers to or incorporates this prospectus, may also contain forward-looking statements. In this prospectus and elsewhere, the words "expects," "believes," "anticipates," "estimates," "projects," "intends," "plans," "probable," "may," "will," "could," "would," "should," and variations of such words and similar expressions, or discussions of strategy or plans, are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ, or that otherwise could impact us or our subsidiaries, include but are not limited to:

- supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which our generating units have access;
- the cost and availability of coal, natural gas and fuel oil, and associated transportation;
- market volatility and other market conditions that could increase our obligations to post collateral beyond the amounts currently expected, and the potential effect of such conditions on our ability and the ability of our subsidiaries to provide sufficient collateral in support of their hedging activities and purchases of fuel;
- the cost and availability of emission credits or allowances;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- governmental, statutory, regulatory or administrative changes or initiatives affecting us or the electricity industry generally, including the market structure rules applicable to each market;
- environmental regulations that could require additional expenditures or otherwise affect our cost and manner of doing business;

- our ability to successfully implement our business strategy, including development projects and future acquisitions;
- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities and technologies that may be able to produce electricity at a lower cost than our generating facilities and/or increased access by competitors to our markets as a result of transmission upgrades;
- our ability to borrow funds and access capital markets on favorable terms;
- the difficulty of predicting wholesale prices, transmission congestion, energy demand, and other aspects of the complex and volatile markets in which we and our subsidiaries participate;
- operating risks, including equipment failure, availability, heat rate, output and availability and cost of spare parts and repairs;
- project development risks, including those related to siting, financing, construction, permitting, and governmental approvals;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- our continued participation and the continued participation by our subsidiaries in tax-allocation and payment agreements with our respective affiliates.

Readers are urged to read this entire prospectus and carefully consider the risks, uncertainties and other factors that affect our business. There may be other factors that may cause our actual results to differ materially from the results referred to in the forward-looking statements. All forward-looking statements attributable to us or persons acting on our behalf apply only as of the date of this prospectus and are expressly qualified in their entirety by the cautionary statements included in this prospectus. We undertake no obligation to publicly update or revise any forward-looking statement whether as a result of new information, future events or otherwise. Readers should review future reports filed by us with the SEC.

INDUSTRY AND MARKET DATA

Industry and market data used throughout this prospectus were obtained through internal company research, surveys and studies conducted by third parties and industry and general publications. Neither we nor the initial purchasers have independently verified, or make any representations about the accuracy of, market and industry data from third-party sources. While we believe internal company estimates are reliable and market definitions are appropriate, they have not been verified by any independent sources, and neither we nor the initial purchasers make any representations about the accuracy of such estimates.

NOTICE TO NEW HAMPSHIRE RESIDENTS

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENSE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE UNIFORM SECURITIES ACT ("RSA 421-B"), WITH THE STATE OF NEW HAMPSHIRE NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW HAMPSHIRE CONSTITUTES A FINDING BY THE SECRETARY OF STATE THAT ANY DOCUMENT FILED UNDER RSA 421-B IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXEMPTION OR EXCEPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THAT THE SECRETARY OF STATE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY, OR TRANSACTION. IT IS UNLAWFUL TO MAKE, OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER OR CLIENT ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

SUMMARY

This summary highlights information about us and the exchange offer. This summary may not contain all the information that is important to you. Therefore, you should read this summary and the more detailed information appearing elsewhere in this prospectus. We encourage you to read this prospectus in its entirety. In this prospectus, the terms "the Company," "we," "our," "ours" and "us" refer to Edison Mission Energy, or EME, and its direct and indirect subsidiaries unless otherwise stated or the context otherwise requires. You should consider the issues discussed in the "Risk Factors" section beginning on page 13 in evaluating your investment in the New Notes.

Edison Mission Energy

We are an independent power producer engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. We also conduct hedging and energy trading activities in power markets open to competition. We are a wholly owned subsidiary of Mission Energy Holding Company, or MEHC. Edison International is our ultimate parent company. Edison International also owns Southern California Edison Company, one of the largest electric utilities in the United States.

We were formed in 1986 with two domestic operating power plants. As of June 30, 2007, our subsidiaries and affiliates owned or leased interests in 32 operating power plants with an aggregate net physical capacity of 10,670 megawatts (MW), of which our capacity pro rata share was 9,500 MW. At June 30, 2007, six projects totaling 293 MW of generating capacity were under construction.

We operate in one line of business, independent power production, with all our continuing operations located in the United States, except the Doga project in Turkey. Operating revenues are primarily related to the sale of power generated from the fossil fuel plants owned by our indirect subsidiary, Midwest Generation, LLC, located in Illinois, and the Homer City electric generating station, located in Pennsylvania. We have substantially expanded our activities with respect to the development of renewable energy projects, particularly wind. We are headquartered in Irvine, California, with additional offices located in Chicago, Illinois and Boston, Massachusetts.

We are a Delaware corporation. Our principal executive offices are located at 18101 Von Karman Avenue, Suite 1700, Irvine, California 92612 and our telephone number at that address is (949) 752-5588. You can find more information about us posted on the Internet website maintained by our ultimate parent, Edison International, at www.edison.com. The information on Edison International's website is not part of this prospectus.

Overview of Facilities

As of June 30, 2007, our operations consisted of ownership or leasehold interests in the following operating power plants:

Power Plants	Location	Primary Electric Purchaser(2)	Fuel Type	Ownership Interest	Net Physical Capacity (in MW)	EME's Capacity Pro Rata Share (in MW)	Number of Plants
Merchant Power Plants							
Illinois Plants(1)	Illinois	PJM	Coal/Oil/Gas	100%	5,918	5,918	6
Homer City(1)	Pennsylvania	PJM	Coal	100%	1,884	1,884	1
Contracted Power Plants							
Domestic							
Big 4 Projects							
Kern River(1)	California	SCE	Natural Gas	50%	300	150	1
Midway-Sunset(1)	California	SCE	Natural Gas	50%	225	113	1
Sycamore(1)	California	SCE	Natural Gas	50%	300	150	1
Watson	California	SCE	Natural Gas	49%	385	189	1
Westside Projects							
Coalinga(1)	California	PG&E	Natural Gas	50%	38	19	1
Mid-Set(1)	California	PG&E	Natural Gas	50%	38	19	1
Salinas River(1)	California	PG&E	Natural Gas	50%	38	19	1
Sargent Canyon(1)	California	PG&E	Natural Gas	50%	38	19	1
American Bituminous(1)	West Virginia	MPC	Waste Coal	50%	80	40	1
March Point	Washington	PSE	Natural Gas	50%	140	70	1
Sunrise(1)	California	CDWR	Natural Gas	50%	572	286	1
Huntington	New York	LIPA	Biomass	38%	25	9	1
San Juan Mesa(1)	New Mexico	SPS	Wind	75%	120	90	1
Minnesota Wind Projects	Minnesota	NSPC/IPLC	Wind	75-99%	83	75	7
Iowa Wind Projects							
Storm Lake	Iowa	MEC	Wind	100%	109	109	1
Crosswinds	Iowa	CBPC	Wind	99%	21	21	1
Hardin	Iowa	IPLC	Wind	99%	15	15	1
Wildorado	Texas	SPS	Wind	99.9%	161	161	1
International							
Doga(1)	Turkey	TEDAS	Natural Gas	80%	180	144	1
Total					10,670	9,500	32

(1) Plant is operated under contract by an operations and maintenance subsidiary of ours (partially owned plants) or plant is operated directly by a subsidiary of ours (wholly owned plants).

(2) Electric purchaser abbreviations are as follows:

PJM	PJM Interconnection, LLC	SPS	Southwestern Public Service
SCE	Southern California Edison Company	NSPC	Northern States Power Company
PG&E	Pacific Gas & Electric Company	IPLC	Interstate Power and Light Company
MPC	Monongahela Power Company	MEC	Mid-American Energy Company
PSE	Puget Sound Energy, Inc.	CBPC	Corn Belt Power Cooperative
CDWR	California Department of Water Resources	TEDAS	Türkiye Elektrik Dagitim Anonim Sirketi

LIPA	Long Island Power Authority

Refinancing Plans

Tender offers and consent solicitations. On April 17, 2007, we and two of our affiliates launched tender offers as follows:

- We launched a tender offer for any and all $600 million of our outstanding 7.73% senior notes due 2009 (the "EME 2009 Notes").

- Our parent, MEHC, launched a tender offer for any and all $800 million of its outstanding 13.50% senior secured notes due 2008.

- Our subsidiary, Midwest Generation, LLC, launched a tender offer for any and all $1 billion of its outstanding 8.75% second priority senior secured notes due 2034.

Each tender offer was combined with a solicitation of consents from registered holders of the notes to amendments to the indentures pursuant to which the notes were issued, in each case, to eliminate substantially all the restrictive covenants, eliminate or modify certain events of default, eliminate or modify related provisions contained in each indenture and, in the case of the MEHC senior secured notes and the Midwest Generation second priority senior secured notes, to release the collateral securing such notes. In addition, MEHC and Midwest Generation solicited consents to the release of security interests in the collateral securing the notes issued by them. These transactions are referred to as the Tender Offers and Consent Solicitations in this prospectus.

On May 15, 2007, we completed our Tender Offers and Consent Solicitations. The amendments to the indentures pursuant to which these notes were issued, which were proposed in connection with the Tender Offers and Consent Solicitations, became operative. The amendments to the indentures eliminated substantially all the restrictive covenants, eliminated or modified certain events of default and eliminated or modified related provisions contained in each indenture. In addition, the collateral securing each of the MEHC senior secured notes and Midwest Generation second priority senior secured notes was released.

Notes offering. On May 7, 2007, EME completed a private offering of $1.2 billion of its 7.00% senior notes due May 15, 2017, $800 million of its 7.20% senior notes due May 15, 2019 and $700 million of its 7.625% senior notes due May 15, 2027. EME will pay interest on the senior notes on May 15 and November 15 of each year, beginning on November 15, 2007.

The senior notes are EME's senior unsecured obligations, ranking in equal right of payment to all EME's existing and future senior unsecured indebtedness, and will be senior to all EME's future subordinated indebtedness. EME's secured debt and its other secured obligations are effectively senior to the senior notes to the extent of the value of the assets securing such debt or other obligations. None of EME's subsidiaries have guaranteed the senior notes and, as a result, all of the existing and future liabilities of EME's subsidiaries are effectively senior to the senior notes.

EME used the net proceeds of the offering of the senior notes, together with cash on hand, to purchase substantially all of EME's outstanding 7.73% senior notes due 2009, to purchase substantially all of Midwest Generation's 8.75% second priority senior secured notes due 2034, to repay the outstanding amount ($327.8 million) of Midwest Generation's senior secured term loan facility, and to make a dividend payment of $899 million to MEHC which enabled MEHC to purchase substantially all of its 13.5% senior secured notes due 2008. The net proceeds of the offering of the senior notes, together with cash on hand, were also used to pay related tender premiums, consent fees, and accrued interest. EME recorded a total pre-tax loss of approximately $160 million (approximately $98 million after tax) on early extinguishment of debt during the second quarter of 2007.

Redemption of MEHC Senior Secured Notes. On June 25, 2007, MEHC redeemed in full its senior secured notes. As a result of the redemption, we are no longer subject to financial and investment restrictions that were contained in the indenture pursuant to which the senior secured notes were issued. Following the redemption, MEHC no longer files reports with the U.S. Securities and Exchange Commission.

Credit Agreement Amendments. During the second quarter of 2007, we amended our existing $500 million secured credit facility, increasing the total borrowings available thereunder to $600 million, and Midwest Generation amended and restated its existing $500 million senior secured working capital facility. The changes to the senior secured working capital facility included a reduction in the interest rate, a longer maturity date, and fewer restrictive covenants. Midwest Generation intends to use its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation may also support its hedging activities by granting first or second priority liens to eligible hedge counterparties.

The Exchange Offer

As part of our Old Notes offering, which was completed on May 7, 2007, we entered into a registration rights agreement in respect of the Old Notes in which we agreed, among other things, to deliver this prospectus to you and to complete an exchange offer for the Old Notes. Below is a summary of the terms of the exchange offer.

Securities Offered	$2,700,000,000 principal amount of New Notes, consisting of: $1,200,000,000 principal amount of 7.00% Senior Notes due May 15, 2017 (the "New Tranche A Notes"); $800,000,000 principal amount of 7.20% Senior Notes due May 15, 2019 (the "New Tranche B Notes"); and $700,000,000 principal amount of 7.625% Senior Notes due May 15, 2027 (the "New Tranche C Notes" and, together with the New Tranche A Notes and the New Tranche B Notes, the "New Notes"). The form and terms of each tranche of these New Notes are identical in all material respects to those of the corresponding tranche of Old Notes. The New Notes, however, will not contain transfer restrictions and registration rights applicable to the Old Notes.
The Exchange Offer	We are offering to issue up to $2,700,000,000 aggregate principal amount of the New Notes in exchange for a like principal amount of the Old Notes in order to satisfy our obligations under the registration rights agreement that we entered into when the Old Notes were issued.
Expiration Date; Tenders	The exchange offer will expire at 5:00 p.m., New York City time, on ____________, 2007, unless extended in our sole and absolute discretion. By tendering your Old Notes, you represent that: you are not our "affiliate," as defined in Rule 405 under the Securities Act; any New Notes you receive in the exchange offer are being acquired by you in the ordinary course of your business; at the time of commencement of the exchange offer, neither you nor, to your knowledge, anyone receiving New Notes from you, has any arrangement or understanding with any person to participate in the distribution, as defined in the Securities Act, of the Old Notes or the New Notes in violation of the Securities Act; if you are not a participating broker-dealer, you are not engaged in, and do not intend to engage in, the distribution, as defined in the Securities Act, of the Old Notes or the New Notes; and

	if you are a broker-dealer, you will receive the New Notes for your own account in exchange for Old Notes that were acquired by you as a result of your market-making or other trading activities and that, you will deliver a prospectus in connection with any resale of the New Notes you receive. For further information regarding resales of the New Notes by participating broker-dealers, see "Plan of Distribution."
	We will extend the duration of the exchange offer as required by applicable law, and may choose to extend if we decide to give holders of Old Notes more time to tender their Old Notes.
Withdrawal; Non-Acceptance	You may withdraw any Old Notes tendered in the exchange offer at any time prior to 5:00 p.m., New York City time, on ____________, 2007. If for any reason the tender of any Old Notes is not accepted for exchange, such withdrawn or unaccepted Old Notes will be credited to the tendering holder's account at The Depository Trust Company, or DTC. For further information regarding the withdrawal of tendered Old Notes, see "The Exchange Offer Terms of the Exchange Offer" and "The Exchange Offer Withdrawal Rights."
Conditions to the Exchange Offer	The exchange offer is subject to certain conditions, which we may waive. See "The Exchange Offer Conditions to the Exchange Offer" for more information regarding the conditions to the exchange offer.
Procedures for Tendering Old Notes	To participate in the exchange offer, you must tender your Old Notes by using the book-entry transfer procedures described below and transmitting an agent's message to the exchange agent on or prior to the expiration or termination of the exchange offer. In order for a book-entry transfer to constitute a valid tender of your Old Notes in the exchange offer, Wells Fargo Bank, National Association, as exchange agent, must receive a confirmation of book-entry transfer of your Old Notes into the exchange agent's account at DTC prior to the expiration or termination of the exchange offer. For more information regarding the use of book-entry transfer procedures, including a description of the required agent's message, see "The Exchange Offer Book-Entry Transfer."
Special Procedures for Beneficial Owners	If you are a beneficial owner whose Old Notes are registered in the name of the broker, dealer, commercial bank, trust company or other nominee and you wish to tender your Old Notes in the exchange offer, you should promptly contact the person in whose name the Old Notes are registered, and instruct that person to tender on your behalf.

Certain U.S. Federal Income Tax Consequences	The exchange of Old Notes for New Notes pursuant to the exchange offer will not be a taxable transaction for U.S. federal income tax purposes. See "Material U.S. Federal Income Tax Consequences" for more information regarding the tax consequences of the exchange offer to you.
Use of Proceeds	We will not receive any cash proceeds from the exchange offer.
Exchange Agent	Wells Fargo Bank, National Association is the exchange agent for the exchange offer. You can find the address and telephone number of the exchange agent below in "The Exchange Offer Exchange Agent."
Resales	Based on interpretations by the staff of the SEC, as set forth in no-action letters issued to third parties, we believe that the New Notes issued in the exchange offer may be offered for resale, resold or otherwise transferred by you without compliance with the registration and prospectus delivery requirements of the Securities Act as long as:
	you are not an affiliate of ours or a broker-dealer that acquired the Old Notes directly from us;
	you are acquiring the New Notes in the ordinary course of your business; and
	you are not participating, do not intend to participate and have no arrangement or understanding with any person to participate, in a distribution of the Old Notes or the New Notes.
	If you are an affiliate of ours or are engaged in or intend to engage in or have any arrangement or understanding with any person to participate in the distribution of the Old Notes or the New Notes:
	you cannot rely on the applicable interpretations of the staff of the SEC; and
	you must comply with the registration requirements of the Securities Act in connection with any resale transaction.
	Each broker or dealer that receives New Notes for its own account in exchange for Old Notes that were acquired as a result of market-making or other trading activities may be deemed an underwriter and thus must acknowledge that it will comply with the registration and prospectus delivery requirements of the Securities Act in connection with any offer, resale, or other transfer of the New Notes issued in the exchange offer, including the delivery of a prospectus that contains information with respect to any selling holder required by the Securities Act in connection with any resale of the New Notes.

	Furthermore, any broker-dealer that acquired any of its Old Notes directly from us may not rely on the applicable interpretation of the SEC staff contained in no-action letters for Exxon Capital Holdings Corp. (available May 13, 1988), Morgan Stanley & Co. Incorporated (available June 5, 1991) and Shearman & Sterling (available July 2, 1993).
	As a condition to participation in the exchange offer, each holder will be required to represent that it is not our affiliate or a broker-dealer that acquired the Old Notes directly from us.
Broker-Dealers	Each broker-dealer that receives New Notes for its own account in exchange for Old Notes, where such Old Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such New Notes. See "Plan of Distribution."
Consequences of Not Exchanging Old Notes	If you do not exchange your Old Notes in the exchange offer, you will continue to be subject to the restrictions on transfer described in the legend on your Old Notes. In general, you may offer or sell your Old Notes only:
	if they are registered under the Securities Act and applicable state securities laws;
	if they are offered or sold under an exemption from registration under the Securities Act and applicable state securities laws; or
	if they are offered or sold in a transaction not subject to the Securities Act and applicable state securities laws.
	We do not currently intend to register the Old Notes under the Securities Act. Under some circumstances, however, holders of the Old Notes, including holders who are not permitted to participate in the exchange offer or who may not freely sell New Notes received in the exchange offer, may require us to file, and to cause to become effective, a shelf registration statement covering resales of the Old Notes by these holders. For more information regarding the consequences of not tendering your Old Notes and our obligations to file a shelf registration statement, see "The Exchange Offer Consequences of Exchanging or Failing to Exchange Old Notes."
No Prior Market	The New Notes will be a new issue of securities for which there is no existing market. Accordingly, we cannot assure you that a liquid market for the New Notes will develop or be maintained.

Summary of the Terms of the New Notes

The form and the terms of the New Notes and the Old Notes are identical in all material respects, except that the transfer restrictions and registration rights applicable to the Old Notes do not apply to the New Notes. The New Notes will evidence the same debt as the Old Notes and will be governed by the same indenture dated May 7, 2007, the first supplemental indenture dated May 7, 2007, the second supplemental indenture dated May 7, 2007, and the third supplemental indenture dated May 7, 2007 (collectively, the "Indenture").

Issuer	Edison Mission Energy
New Notes Offered	$2,700,000,000 principal amount of New Notes, consisting of:
	$1,200,000,000 principal amount of New Tranche A Notes;
	$800,000,000 principal amount of New Tranche B Notes; and
	$700,000,000 principal amount of New Tranche C Notes.
Maturity Dates	Maturity dates of New Notes, consisting of:
	New Tranche A Notes May 15, 2017
	New Tranche B Notes May 15, 2019
	New Tranche C Notes May 15, 2027
Interest Payment Dates	Interest on the New Notes will accrue from May 7, 2007, and will be paid semi-annually in arrears on May 15 and November 15 of each year, commencing on November 15, 2007.
Ranking	The New Notes will be our senior unsecured obligations, will rank pari passu with all of our existing and future unsecured indebtedness and will rank senior to our future subordinated indebtedness. All existing and future liabilities of our subsidiaries will be effectively senior to the New Notes.
Certain Covenants	The Indenture governing the New Notes contains covenants limiting or prohibiting EME's ability to, among other things:
	create liens,
	incur secured indebtedness, and
	merge or consolidate with other entities.
	These covenants are subject to important qualifications and exceptions. See "Description of the New Notes Certain Covenants."
Repurchase of Notes upon a Change of Control	If a Change of Control Triggering Event (as defined in the Description of the New Notes) occurs, we will be required to offer to repurchase the New Notes at a price equal to 101% of the principal thereof as described under "Description of the New Notes Repurchase of Notes at the Option of the Holder upon a Change of Control."

Optional Redemption	We may redeem some or all of the New Notes at any time at a price equal to 100% of the principal amount of, plus accrued and unpaid interest on, the New Notes being redeemed plus a "make-whole" premium. See "Description of the New Notes Redemption."
Risk Factors	See "Risk Factors" for a discussion of certain factors that should be considered in evaluating an investment in the New Notes.

Summary Consolidated Financial Data

The following table sets forth a summary of our consolidated financial data for the periods indicated. The historical consolidated operating data for each of the three years ended December 31, 2006 and the financial position data as of December 31, 2006 and 2005 were derived from the audited historical consolidated financial statements included elsewhere in this prospectus. The following selected historical consolidated financial data as of June 30, 2007 and for the six months ended June 30, 2007 and 2006 has been derived from our unaudited consolidated financial statements included elsewhere in this prospectus. Our unaudited consolidated financial statements were prepared on a basis consistent with that used in preparing our audited consolidated financial statements and include all material adjustments, all of which are of a normal recurring nature, that, in the opinion of management, are necessary for a fair statement of our financial position and results of operations for the unaudited periods.

You should read the following information in conjunction with the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and the related notes included elsewhere in this prospectus. Historical results are not necessarily indicative of results that may be expected for any future period.

	Years Ended December 31,			Six Months Ended June 30,	
	2004	2005	2006	2006	2007
		(in millions)		(in millions) (unaudited)	
Income Statement Data					
Operating revenues	$ 1,653	$ 2,265	$ 2,239	$ 977	$ 1,243
Operating expenses					
Fuel, plant operations and plant operating lease	1,300	1,287	1,332	658	729
Loss on lease termination, asset impairment and other charges and credits	989	7		(5)	
Depreciation and amortization	152	134	144	71	76
Administrative and general	149	154	140	64	84
Total Operating Expenses	2,590	1,582	1,616	788	889
Operating income (loss)	(937)	683	623	189	354
Equity in income from unconsolidated affiliates	218	229	186	71	80
Impairment loss on equity method investment		(55)			
Interest and other income	52	69	120	61	57
Interest expense	(298)	(300)	(279)	(145)	(129)
Loss on early extinguishment of debt		(4)	(146)	(143)	(160)
Income (loss) from continuing operations before income taxes and minority interest	(965)	622	504	33	202
Provision (benefit) for income taxes	(406)	208	189	1	68
Minority interest	(1)		1		
Income (loss) from continuing operations	(560)	414	316	32	134
Income from operations of discontinued subsidiaries (including gain on disposal of $533 million in 2004), net of tax	690	29	98	77	5
Income before accounting change	130	443	414	109	139
Cumulative effect of change in accounting, net of tax(1)		(1)			
Net income	$ 130	$ 442	$ 414	$ 109	$ 139

(1) The 2005 loss from a change in accounting principle resulted from the adoption of a new accounting standard for conditional asset retirements.

	As of December 31, 2004	As of December 31, 2005	As of December 31, 2006	As of June 30, 2007
	(in millions)			(in millions) (unaudited)
Balance Sheet Data				
Assets	$ 7,087	$ 7,023	$ 7,250	$ 7,114
Current liabilities	994	846	646	504
Long-term obligations	3,530	3,330	3,035	3,845
Shareholder's equity	1,745	1,910	2,582	1,681

	Years Ended December 31, 2004	Years Ended December 31, 2005	Years Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
		(in millions)		(in millions) (unaudited)	
Other Data					
Ratio of earnings to fixed charges(2)(3)		2.23x	2.01x	1.20x	1.71x

(2) For purposes of computing the ratio of earnings to fixed charges, earnings are divided by fixed charges. "Earnings" represent the aggregate of income (loss) for continuing operations before income taxes and minority interest. "Fixed charges" represent interest (whether expensed or capitalized), amortization of debt discount and the interest component of rental expense.

(3) For the year ended December 31, 2004, there was a fixed charge deficiency of $953 million.

RISK FACTORS

Your investment in the New Notes involves a high degree of risk. You should carefully consider the risks described below as well as other information and data included in this prospectus, before making an investment decision. Additional risks and uncertainties not presently known to us or that we currently believe are immaterial may also adversely impact our business operations. If any of the events described in the risk factors below occurs, our business, financial condition, operating results and prospects could be materially adversely affected, which in turn could adversely affect our ability to pay interest and/or principal on the New Notes.

Risks Relating to Exchange Offer

You may have difficulty selling the Old Notes which you do not exchange, since Old Notes will continue to have restrictions on transfer and cannot be sold without registration under securities laws or exemptions from registration.

If a large number of Old Notes are exchanged for New Notes issued in the exchange offer, it may be difficult for holders of Old Notes that are not exchanged in the exchange offer to sell the Old Notes, since those Old Notes may not be offered or sold unless they are registered or there are exemptions from registration requirements under the Securities Act or state laws that apply to them. In addition, if there are only a small number of Old Notes outstanding, there may not be a very liquid market in those Old Notes. There may be few investors that will purchase unregistered securities in which there is not a liquid market. See "The Exchange Offer Consequences of Exchanging or Failing to Exchange Old Notes."

In addition, if you do not tender your Old Notes or if we do not accept some Old Notes, those notes will continue to be subject to the transfer and exchange provisions of the Indenture and the existing transfer restrictions of the Old Notes that are described in the legend on such notes and in the offering memorandum relating to the Old Notes.

Late deliveries of Old Notes or any other failure to comply with the exchange offer procedures could prevent a holder from exchanging its Old Notes.

Noteholders are responsible for complying with all exchange offer procedures. The issuance of New Notes in exchange for Old Notes will only occur upon completion of the procedures described in this prospectus under "The Exchange Offer." Therefore, holders of Old Notes who wish to exchange them for New Notes should allow sufficient time for timely completion of the exchange procedure. Neither we nor the exchange agent are obligated to extend the offer or notify you of any failure to follow the proper procedure.

If you do not exchange your Old Notes in the exchange offer, you will no longer be entitled to an increase in interest payments on Old Notes that the Indenture provides for if we fail to complete the exchange offer.

Once the exchange offer has been completed, holders of outstanding Old Notes will not be entitled to any increase in the interest rate on their notes, which the Indenture provides for if we fail to complete the exchange offer. Holders of Old Notes will not have any further rights to have their Old Notes registered, except in limited circumstances, once the exchange offer is completed.

If you exchange your Old Notes, you may not be able to resell the New Notes you receive in the exchange offer without registering them and delivering a prospectus.

If you exchange your Old Notes in the exchange offer for the purpose of participating in a distribution of the New Notes, you may be deemed to have received restricted securities and, if so, you will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

Based on interpretations by the SEC in no-action letters, we believe, with respect to New Notes issued in the exchange offer, that:

- holders who are not "affiliates" of ours within the meaning of Rule 405 of the Securities Act,

- holders who acquire their notes in the ordinary course of business and

- holders who do not engage in, intend to engage in, or have arrangements to participate in a distribution (within the meaning of the Securities Act) of the notes do not have to comply with the registration and prospectus delivery requirements of the Securities Act.

Holders described in the preceding sentence must tell us in writing at our request that they meet these criteria. Holders that do not meet these criteria could not rely on interpretations of the SEC in no-action letters, and would have to register the New Notes they receive in the exchange offer and deliver a prospectus for them. In addition, holders that are broker-dealers may be deemed "underwriters" within the meaning of the Securities Act in connection with any resale of New Notes acquired in the exchange offer. Holders that are broker-dealers must acknowledge that they acquired their Old Notes in market-making activities or other trading activities and must deliver a prospectus when they resell the New Notes they acquire in the exchange offer in order not to be deemed an underwriter. Our obligation to make this prospectus available to broker-dealers is limited. We cannot guarantee that a proper prospectus will be available to broker-dealers wishing to resell their New Notes.

You should review the more detailed discussion in "The Exchange Offer Procedures for Tendering Old Notes" and "The Exchange Offer Consequences of Exchanging or Failing to Exchange Old Notes."

Risks Relating to Our Business

We have substantial interests in merchant energy power plants which are subject to market risks related to wholesale energy prices.

Our merchant energy power plants do not have long-term power purchase agreements. Because the output of these power plants is not committed to be sold under long-term contracts, these projects are subject to market forces which determine the amount and price of energy, capacity and ancillary services sold from the power plants. The factors that influence the market price for energy, capacity and ancillary services include:

- prevailing market prices for coal, natural gas and fuel oil, and associated transportation;

- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities or technologies that may be able to produce electricity at a lower cost than our generating facilities and /or increased access by competitors to our markets as a result of transmission upgrades;

transmission congestion in and to each market area and the resulting differences in prices between delivery points;

the market structure rules established for each market area and regulatory developments affecting the market areas, including any price limitations and other mechanisms adopted to address volatility or illiquidity in these markets or the physical stability of the system;

the cost and availability of emission credits or allowances;

the availability, reliability and operation of competing power generation facilities, including nuclear generating plants where applicable, and the extended operation of such facilities beyond their presently expected dates of decommissioning;

weather conditions prevailing in surrounding areas from time to time; and

changes in the demand for electricity or in patterns of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs.

In addition, unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, the wholesale power markets are subject to significant and unpredictable price fluctuations over relatively short periods of time. There is no assurance that our merchant energy power plants will be successful in selling power into their markets or that the prices received for their power will generate positive cash flows. If our merchant energy power plants do not meet these objectives, they may not be able to generate enough cash to service their own debt and lease obligations, which could have a material adverse effect on us.

Our financial results can be affected by changes in fuel prices, fuel transportation cost increases, and interruptions in fuel supply.

Our business is subject to changes in fuel costs, which may negatively affect our financial results and financial position by increasing the cost of producing power. The fuel markets can be volatile, and actual fuel prices can differ from our expectations.

Although we attempt to purchase fuel based on our known fuel requirements, we are still subject to the risks of supply interruptions, transportation cost increases, and fuel price volatility. In addition, fuel deliveries may not exactly match energy sales, due in part to the need to purchase fuel inventories in advance for reliability and dispatch requirements. The price at which we can sell our energy may not rise or fall at the same rate as a corresponding rise or fall in fuel costs.

We may not be able to hedge market risks effectively.

We are exposed to market risks through our ownership and operation of merchant energy power plants and through our power marketing business. These market risks include, among others, volatility arising from the timing differences associated with buying fuel, converting fuel into energy and delivering energy to a buyer. We use forward contracts and derivative financial instruments, such as futures contracts and options, to manage market risks and exposure to fluctuating electricity and fuel prices. We cannot provide assurance that these strategies will successfully mitigate market risks, or that they will not result in net losses.

We may not cover the entire exposure of our assets or positions to market price volatility, and the level of coverage will vary over time. Fluctuating commodity prices may negatively affect our financial results to the extent that assets and positions have not been hedged.

The effectiveness of our hedging activities may depend on the amount of working capital available to post as collateral in support of these transactions, either in support of performance guarantees or as a cash margin. The amount of credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in a requirement to provide cash collateral and letters of credit in very large amounts. Without adequate liquidity to meet margin and collateral requirements, we could be exposed to the following:

- a reduction in the number of counterparties willing to enter into bilateral contracts, which would result in increased reliance on short-term and spot markets instead of bilateral contracts, increasing our exposure to market volatility; and

- a failure to meet a margining requirement, which could permit the counterparty to terminate the related bilateral contract early and demand immediate payment for the replacement value of the contract.

As a result of these and other factors, we cannot predict with precision the effect that risk management decisions may have on our business, operating results or financial position.

We are exposed to credit and performance risk from third parties under supply and transportation contracts.

We rely on contracts for the supply and transportation of fuel and other services required for the operation of our generation facilities. Our operations are exposed to the risk that counterparties will not perform their obligations. If a counterparty failed to perform under a contract, we would need to obtain alternate suppliers or alternate means of transportation for our requirements of fuel or other services, which could result in higher costs or disruptions in our operations. Furthermore, we are exposed to credit risk because damages related to a breach of contract may not be recoverable. Accordingly, the failure of a supplier to fulfill our contractual obligations could have a material adverse effect on our financial results.

We are subject to extensive energy industry regulation.

Our operations are subject to extensive regulation by governmental agencies. Our projects are subject to federal laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, and access to transmission. Under limited circumstances where exclusive federal jurisdiction is not applicable or specific exemptions or waivers from state or federal laws or regulations are otherwise unavailable, federal and/or state utility regulatory commissions may have broad jurisdiction over non-utility owned electric power plants. Generation facilities are also subject to federal, state and local laws and regulations that govern, among other things, the geographical location, zoning, land use and operation of a project.

The Federal Energy Regulatory Commission may impose various forms of market mitigation measures, including price caps and operating restrictions, where it determines that potential market power might exist and that the public interest requires mitigation. In addition, many of our facilities are subject to rules, restrictions and terms of participation imposed and administered by various regional transmission organizations and independent system operators. For example, independent system operators, also known as ISOs, and regional transmission organizations, also known as RTOs, may impose bidding and scheduling rules, both to curb the potential exercise of market power and to facilitate market functions. Such actions may materially affect our results of operations.

There is no assurance that the introduction of new laws or other future regulatory developments will not have a material adverse effect on our business, results of operations or financial condition, nor is there any assurance that we will be able to obtain and comply with all necessary licenses, permits and approvals for our projects. If projects cannot comply with all applicable regulations, our business, results of operations and financial condition could be adversely affected.

We are subject to extensive environmental regulation and permitting requirements that may involve significant and increasing costs.

Our operations are subject to extensive environmental regulation with respect to, among other things, air quality, water quality, waste disposal, and noise. We are required to obtain and comply with conditions established by licenses, permits and other approvals in order to construct, operate or modify our facilities. Failure to comply with these requirements could subject us to civil or criminal liability, the imposition of liens or fines, or actions by regulatory agencies seeking to curtail our operations.

We devote significant resources to environmental monitoring, pollution control equipment and emission allowances to comply with environmental regulatory requirements. We believe that we are currently in substantial compliance with environmental regulatory requirements. However, the United States Environmental Protection Agency (US EPA) has issued a notice of violation (NOV) to Midwest Generation and Commonwealth Edison Company (Commonwealth Edison), the former owner of Midwest Generation's coal-fired power plants, alleging violations of the Clean Air Act and certain opacity and particulate matter standards. The current trend is toward more stringent standards, stricter regulation, and more expansive application of environmental regulations. Environmental advocacy groups and regulatory agencies in the United States have been focusing considerable attention on carbon dioxide emissions from coal-fired power plants and their potential role in climate change. The adoption of laws and regulations to implement carbon dioxide controls could adversely affect our coal-fired plants. Also, coal plant emissions of nitrogen oxides and sulfur oxides, mercury and particulates are subject to increased controls and mitigation expenses. Additionally, certain of the states in which we operate are contemplating air pollution control regulations that are more stringent than existing and proposed federal regulations. The continued operation of our facilities, particularly our coal-fired facilities, will require substantial capital expenditures for environmental controls.

For example, in December 2006, Midwest Generation entered into an agreement with the Illinois Environmental Protection Agency (Illinois EPA) to reduce mercury, nitrogen oxide and sulfur dioxide emissions at Midwest Generation's Illinois coal-fired power plants. Capital expenditures relating to controls contemplated by the agreement are expected (in 2006 dollars) to be in the range of approximately $2.7 billion to $3.4 billion through 2018. There is no assurance that these capital expenditures will not exceed the above estimates.

In addition, future environmental laws and regulations, and future enforcement proceedings that may be taken by environmental authorities, could affect the costs and the manner in which we conduct our business. There is no assurance that we would be able to recover these increased costs from our customers or that our business, financial position and results of operations would not be materially adversely affected. Furthermore, changing environmental regulations could make some units uneconomical to maintain or operate. If we cannot comply with all applicable regulations, we could be required to retire or suspend operations at our facilities, or restrict or modify the operations of our facilities, and our business, results of operations and financial condition could be adversely affected.

Typically, environmental laws require a lengthy and complex process for obtaining licenses, permits and approvals prior to construction, operation or modification of a project or generating facility. Meeting all the necessary requirements can delay or sometimes prevent the completion of a proposed project as well as require extensive modifications to existing projects, which may involve significant capital expenditures. We cannot provide assurance that we will be able to obtain and comply with all necessary licenses, permits and approvals for our plants. If there is a delay in obtaining required approvals or permits or if we fail to obtain and comply with such permits, the operation of our facilities may be interrupted or become subject to additional costs.

Our development projects or future acquisitions may not be successful.

Our future financial condition, results of operations and cash flows will depend in large part upon our ability to successfully implement our long-term strategy, which includes the development and acquisition of electric power generation facilities, with an emphasis on renewable energy (primarily wind), integrated gasification combined cycle, and gas-fired power plants. We may be unable to identify attractive acquisition or development opportunities and/or to complete and integrate them on a successful and timely basis. Furthermore, implementation of this strategy may be affected by factors beyond our control, such as increased competition, legal and regulatory developments, price volatility in electric or fuel markets, and general economic conditions.

In support of our development activities, we have entered into commitments to purchase wind turbines for future projects and plan to make substantial additional commitments in the future. In addition, we expend significant amounts for preliminary engineering, permitting, legal and other expenses before we can determine whether we will win a competitive bid, or whether a project is feasible or economically attractive.

Our development activities are subject to risks including, without limitation, risks related to project siting, financing, construction, permitting, and governmental approvals. We may not be successful in developing new projects or the timing of such development may be delayed beyond the date such turbines are ready for installation. Furthermore, we may not be able to obtain financing for new projects that are developed and may not be able to obtain sufficient equity capital or additional borrowings to enable us to fund equity commitments for future projects. Recent disruptions in the credit markets have impacted the availability of credit, cost of borrowing, and terms and conditions of new borrowings. It is uncertain whether these market conditions will affect our ability to obtain financing for new projects or the terms and conditions of future financings. If a project under development is abandoned, we would expense all capitalized costs incurred in connection with that project, and could incur additional losses associated with any related contingent liabilities. If we are not successful in developing new projects, we may be required to sell turbines that were purchased and such sales may result in substantial losses.

Finally, we cannot provide assurance that our development projects or acquired assets will generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them, or that we will ultimately realize a satisfactory rate of return.

Competition could adversely affect our business.

The independent power industry is characterized by numerous capable competitors, some of whom may have more extensive operating experience in the acquisition and development of power projects, larger staffs, and greater financial resources than we do. Several participants in the wholesale markets, including many regulated utilities, have a lower cost of capital than most merchant generators and often are able to recover fixed costs through rate base mechanisms, allowing them to build, buy and upgrade generation assets without relying exclusively on market clearing prices to recover their investments. This could affect our ability to compete effectively in the markets in which those entities operate.

Newer plants owned by our competitors are often more efficient than our facilities. This may put some of our facilities at a competitive disadvantage to the extent that our competitors are able to produce more power from each increment of fuel than our facilities are capable of producing. Over time, some of our facilities may become obsolete in their markets, or be unable to compete, because of the construction of newer, more efficient power plants.

In addition to the competition already existing in the markets in which we presently operate or may consider operating in the future, we are likely to encounter significant competition as a result of further consolidation of the power industry by mergers and asset reallocations, which could create powerful new competitors, and new market entrants such as investment companies. In addition, the Energy Policy Act of 2005 (EPAct 2005) and other regulatory initiatives may result in changes in the power industry to which we may not be able to respond in as timely and effective manner as our competitors.

We may not be able to raise capital on favorable terms, to refinance our or our subsidiaries' existing indebtedness, or to fund operations, capital expenditures, and future acquisitions and development activities, which could adversely affect our results of operations.

The factors that influence our ability to arrange for financing and our costs of capital include:

- general economic and capital market conditions;
- the availability of bank credit;
- investor confidence;
- the financial condition, performance, prospects, and credit ratings of us and/or the subsidiary requiring the financing; and
- changes in tax and securities laws.

Recent disruptions in the credit markets have impacted the availability of credit, cost of borrowing, and terms and conditions of new borrowings. We cannot provide assurance that our projected sources of capital will be available when needed or that our actual cash requirements will not be greater than expected.

Restrictions in the instruments governing our indebtedness and the indebtedness of our subsidiaries limit our and our subsidiaries' ability to enter into specified transactions that we otherwise may enter into.

The instruments governing our indebtedness and the indebtedness of our subsidiaries contain financial and investment covenants. Restrictions contained in these documents or documents we or our subsidiaries enter in the future could affect, and in some cases significantly limit or prohibit, our ability and the ability of our subsidiaries to, among other things, incur, refinance, and prepay debt, make capital expenditures, pay dividends and make other distributions, make investments, create liens, sell assets, enter into sale and leaseback transactions, issue equity interests, enter into transactions with affiliates, create restrictions on the ability to pay dividends or make other distributions and engage in mergers and consolidations. These restrictions may significantly impede our ability and the ability of our subsidiaries to take advantage of business opportunities as they arise, to grow our business or to compete effectively. In addition, these restrictions may significantly impede the ability of our subsidiaries to make distributions to us.

Our projects may be affected by general operating risks and hazards customary in the power generation industry. We may not have adequate insurance to cover all these hazards.

The operation of power generation facilities involves many operating risks, including:

- performance below expected levels of output or efficiency;
- interruptions in fuel supply;
- disruptions in the transmission of electricity;
- curtailment of operations due to transmission constraints;
- breakdown or failure of equipment or processes;
- imposition of new regulatory, permitting, or environmental requirements, or violations of existing requirements;
- employee work force factors, including strikes, work stoppages or labor disputes;
- operator/contractor error; and
- catastrophic events such as terrorist activities, fires, tornadoes, earthquakes, explosions, floods or other similar occurrences affecting power generation facilities or the transmission and distribution infrastructure over which power is transported.

These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of or damage to the environment, and suspension of operations. The occurrence of one or more of the events listed above could decrease or eliminate revenues generated by our projects or significantly increase the costs of operating them, and could also result in our being named as a defendant in lawsuits asserting claims for substantial damages, potentially including environmental cleanup costs, personal injury, property damage, fines and penalties. Equipment and plant warranties and insurance may not be sufficient or effective under all circumstances to cover lost revenues or increased expenses. A decrease or elimination in revenues generated by the facilities or an increase in the costs of operating them could decrease or eliminate funds available to meet our obligations as they become due and could have a material adverse effect on us. A default under a financing obligation of a project entity could result in a loss of our interest in the project.

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

We engage in hedging activities in order to mitigate our exposure to market risk with respect to electricity sales from our generation facilities, fuel utilized by those facilities and emissions allowances. We generally attempt to balance our fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. We also use derivative contracts with respect to our limited proprietary trading activities, through which we attempt to achieve incremental returns by transacting where we have specific market expertise. These derivative contracts are recorded on our balance sheet at fair value pursuant to SFAS No. 133. Some of these derivative contracts do not qualify under SFAS No. 133 for hedge accounting, and changes in their fair value are therefore recognized currently in earnings as unrealized gains or losses. As a result, our financial results, including gross margin, operating income and balance sheet ratios, will at times be volatile and subject to fluctuations in value primarily due to changes in electricity and fuel prices.

Risks Relating to the New Notes

We are primarily a holding company. Our only material source of cash is and will be distributions from our subsidiaries, and the New Notes will be effectively subordinated to the claims of our direct and indirect subsidiaries.

We are primarily a holding company with no material business operations of our own. Our most significant assets are the capital stock of our subsidiaries. We conduct virtually all of our business operations through those subsidiaries. Accordingly, our only material source of cash, including cash to make payments on or redeem the New Notes or our other indebtedness, is and will be dividends and distributions with respect to our ownership interests in our subsidiaries that are derived from the earnings and cash flow generated by our subsidiaries. We cannot assure you that our subsidiaries will generate sufficient earnings and cash flow to pay dividends or distributions to us or that applicable state law and contractual restrictions binding on our subsidiaries will permit dividends or distributions in the future. See " Restrictions in the instruments governing our indebtedness and the indebtedness of our subsidiaries limit our and our subsidiaries' ability to enter into specified transactions that we otherwise may enter into." In addition, our direct and indirect subsidiaries will not guarantee the New Notes and will have no legal obligations to make payments on the New Notes or make funds available for those payments, whether by dividends, loans or other payments. Accordingly, we may not be able to pay interest on the New Notes or principal when due at maturity or otherwise.

In the event of a bankruptcy, liquidation, dissolution, reorganization or similar proceeding involving us, the New Notes will be effectively subordinated to the claims of the creditors of all of our direct and indirect subsidiaries, including trade creditors and holders of indebtedness of those subsidiaries. Accordingly, there might only be a limited amount of assets available to satisfy your claims as a holder of the New Notes upon an acceleration of the maturity of the New Notes.

We have a substantial amount of indebtedness, including long-term lease obligations.

As of June 30, 2007, our consolidated debt was $4.0 billion. In addition, our subsidiaries had $4.0 billion of long-term power plant lease obligations due over a period ranging up to 28 years. Subject to certain exceptions, the indenture governing the New Notes limits our ability to incur secured debt to 15% of our consolidated net tangible assets, but will not impose limitations on our ability to incur additional unsecured indebtedness. See "Description of the New Notes Certain covenants; restrictions on liens." All existing and future liabilities of our subsidiaries will be effectively senior to the New Notes. In addition, our $600 million secured credit facility is secured by the stock of certain of our subsidiaries. The New Notes will be junior to borrowings under this facility and any secured indebtedness we may incur in the future to the extent of the collateral securing such indebtedness.

The substantial amount of consolidated debt and financial obligations presents the risk that we might not have sufficient cash to service our indebtedness, including the New Notes, or long-term lease obligations and that the existing corporate debt, project debt and lease obligations could limit our ability to grow our business, to compete effectively or operate successfully under adverse economic conditions, or to plan for and react to business and industry changes. If our or our subsidiaries' cash flows and capital resources were insufficient to allow us to make scheduled payments on our debt, we might have to reduce or delay capital expenditures, sell assets, seek additional capital, or restructure or refinance the debt. The terms of our or our subsidiaries' debt may not allow these alternative measures, the debt or equity may not be available on acceptable terms, and these alternative measures may not satisfy all scheduled debt service obligations.

In addition, in connection with the entry into new financings or amendments to existing financing arrangements, our financial and operational flexibility may be further reduced as a result of more restrictive covenants, requirements for security and other terms that are often imposed on sub-investment grade entities.

You may find it difficult to sell your notes because there is no existing trading market for the New Notes.

You may find it difficult to sell your notes because an active trading market for the notes may not develop. The New Notes are being offered to the holders of the Old Notes. The Old Notes were issued on May 7, 2007, primarily to a small number of institutional investors. After the exchange offer, the trading market for the remaining untendered Old Notes could be adversely affected. There is no existing trading market for the New Notes. Future trading prices of the New Notes will depend on many factors, including prevailing interest rates, our operating results, and the market for similar securities. We do not intend to apply for listing or quotation of the New Notes on any exchange, and so we do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. Although the initial purchasers in the private offering of the Old Notes have informed us that they intend to make a market in the New Notes, they are not obligated to do so. The initial purchasers may cease their market-making at any time. As a result, the market price of the New Notes could be adversely affected.

Historically, the market for non-investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the New Notes offered by this prospectus. The market for the New Notes, if any, may be subject to similar disruptions. These disruptions may adversely affect the value of the New Notes.

THE EXCHANGE OFFER

Purpose of the Exchange Offer

When we sold the Old Notes on May 7, 2007, or the "closing date," we entered into a registration rights agreement with the initial purchasers of the Old Notes. Under the registration rights agreement, we agreed to file a registration statement regarding the exchange of the Old Notes for New Notes which are registered under the Securities Act. We also agreed to use our reasonable best efforts to cause the registration statement to become effective with the SEC and to conduct this exchange offer after the registration statement is declared effective. The registration rights agreement provides that we will be required to pay additional interest to the holders of the Old Notes if:

- we do not file the exchange offer registration statement with the SEC on or prior to the 180th calendar day following the closing date;
- the exchange offer registration statement has not been declared effective on or prior to the 240th calendar day following the closing date; or
- the exchange offer is not consummated on or prior to 30 business days after the 240th calendar day following the closing date.

The exchange offer is not being made to holders of Old Notes in any jurisdiction where the exchange would not comply with the securities or blue sky laws of such jurisdiction. A copy of the registration rights agreement is filed as an exhibit to the registration statement of which this prospectus forms a part.

Each broker-dealer that receives New Notes for its own account in exchange for Old Notes, where such New Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, will acknowledge that it will deliver a prospectus in connection with any resale of the New Notes. See "Plan of Distribution."

Terms of the Exchange Offer

Upon the terms and conditions described in this prospectus, we will accept for exchange Old Notes that are properly tendered on or before the expiration date and not withdrawn as permitted below. As used in this prospectus, the term "expiration date" means 5:00 p.m., New York City time, on ____________, 2007. However, if we, in our sole discretion, have extended the period of time for which the exchange offer is open, the term "expiration date" means the latest time and date to which we extend the exchange offer.

As of the date of this prospectus, $2,700,000,000 aggregate principal amount at maturity of the Old Notes is outstanding. The Old Notes were offered under the Indenture. This prospectus is first being sent on or about ____________, 2007 to all holders of Old Notes known to us. Our obligation to accept Old Notes for exchange in the exchange offer is subject to the conditions described below under " Conditions to the Exchange Offer." We reserve the right to extend the period of time during which the exchange offer is open. We would then delay acceptance for exchange of any Old Notes by giving oral or written notice of an extension to the holders of Old Notes as described below. During any extension period, all Old Notes previously tendered will remain subject to the exchange offer and may be accepted for exchange by us. Any Old Notes not accepted for exchange will be returned to the tendering holder after the expiration or termination of the exchange offer. Holders of Old Notes do not have dissenters' rights of appraisal in connection with the exchange offer.

Old Notes tendered in the exchange offer must be in denominations of principal amount of $2,000 and any integral multiple of $1,000.

We reserve the right to amend or terminate the exchange offer, and not to accept for exchange any Old Notes not previously accepted for exchange, upon the occurrence of any of the conditions of the exchange offer specified below under " Conditions to the Exchange Offer." We will give oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the Old Notes as promptly as practicable. We will notify you of any extension by means of a press release or other public announcement no later than 9:00 a.m., New York City time on that date.

Our acceptance of the tender of Old Notes by a tendering holder will form a binding agreement upon the terms and subject to the conditions provided in this prospectus.

Procedures for Tendering

A tendering holder must, on or prior to the expiration date, transmit an agent's message to the exchange agent at the address listed below under the heading " Exchange Agent."

In addition, the exchange agent must receive, on or before the expiration date, a timely confirmation of book-entry transfer of the Old Notes into the exchange agent's account at the DTC, the book-entry transfer facility, along with an agent's message.

The term "agent's message" means a message, transmitted to DTC and received by the exchange agent and forming a part of a book-entry transfer, that states that DTC has received an express acknowledgment that the tendering holder agrees to appoint the exchange agent as the tendering holder's true and lawful agent and attorney-in-fact with respect to such tendered Old Notes, with full power of substitution, among other things, to cause the Old Notes to be assigned, transferred and exchanged.

If you are a beneficial owner whose Old Notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee, and wish to tender, you should promptly instruct the registered holder to tender on your behalf.

We will determine in our sole discretion all questions as to the validity, form and eligibility of Old Notes tendered for exchange. This discretion extends to the determination of all questions concerning the timing of receipts and acceptance of tenders. These determinations will be final and binding.

We reserve the right to reject any amount of Old Notes not properly tendered, or any acceptance that might, in our judgment or our counsel's judgment, be unlawful. We also reserve the right to waive any conditions of the exchange offer as applicable to all Old Notes prior to the expiration date. We also reserve the right to waive any defects or irregularities or conditions of the exchange offer as to any amount of Old Notes prior to the expiration date. Our interpretation of the terms and conditions of the exchange offer as to any amount of Old Notes either before or after the expiration date shall be final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of Old Notes must be cured within a reasonable period of time. None of we, the exchange agent or any other person will be under any duty to give notification of any defect or irregularity in any tender of Old Notes. Nor will we, the exchange agent or any other person incur any liability for failing to give notification of any defect or irregularity.

By tendering, each holder will represent to us that, among other things:

- the holder is not an affiliate of ours (as defined in Rule 405 under the Securities Act) or a broker-dealer tendering notes acquired directly from us for its own account;
- the New Notes are being acquired in the ordinary course of business of the person receiving the New Notes, whether or not that person is the holder;
- neither the holder nor the other person has any arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the New Notes; and
- the holder is not engaged in, and does not intend to engage in, a distribution of the New Notes.

However, any purchaser of Old Notes who is our "affiliate" (within the meaning of the Securities Act) who intends to participate in the exchange offer for the purpose of distributing the New Notes or a broker-dealer (within the meaning of the Securities Act) that acquired Old Notes in a transaction other than as part of its trading or market-making activities and who has arranged or has an understanding with any person to participate in the distribution of the New Notes:

- will not be able to rely on the applicable interpretation by the staff of the SEC set forth in the applicable no-action letters;
- will not be able to tender its Old Notes in the exchange offer; and
- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the notes unless such sale or transfer is made pursuant to an exemption from such requirements.

By tendering, each broker-dealer that receives New Notes for its own account in exchange for Old Notes, where the Old Notes were acquired by it for its own account as a result of market-making activities or other trading activities, will acknowledge that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the New Notes. By so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. However, a broker-dealer may be a statutory underwriter. See "Plan of Distribution."

Furthermore, any broker-dealer that acquired any of its Old Notes directly from us:

- may not rely on the applicable interpretation of the staff of the SEC's position contained in *Exxon Capital Holdings Corp.*, SEC no-action letter (April 13, 1988), *Morgan, Stanley & Co. Inc.*, SEC no-action letter (June 5, 1991), and *Shearman & Sterling*, SEC no-action letter (July 2, 1993); and
- must also be named as a selling holder in connection with the registration and prospectus delivery requirements of the Securities Act relating to any resale transaction.

Acceptance of Old Notes for Exchange; Delivery of New Notes

Upon satisfaction or waiver of all of the conditions to the exchange offer, we will accept, promptly after the expiration date, all Old Notes properly tendered, unless we terminate the exchange offer

because of the non-satisfaction of conditions. We will issue the New Notes as soon as practicable after acceptance of the Old Notes. See " Conditions to the Exchange Offer" below. For purposes of the exchange offer, we will be deemed to have accepted properly tendered Old Notes for exchange when, as and if we have given oral or written notice to the exchange agent, with prompt written confirmation of any oral notice.

For each Old Note accepted for exchange, the holder of the Old Note will receive a New Note having a principal amount equal to that of the surrendered Old Note. The New Notes will bear interest from the most recent date to which interest has been paid on the Old Notes. Accordingly, registered holders of New Notes on the relevant record date for the first interest payment date following the completion of the exchange offer will receive interest accruing from the most recent date to which interest has been paid. The accreted value of the New Notes will be the same as the accreted value of the Old Notes. Old Notes accepted for exchange will cease to accrue interest from and after the date of completion of the exchange offer. Holders of Old Notes whose Old Notes are accepted for exchange will not receive any payment for accrued interest on the Old Notes otherwise payable on any interest payment date, the record date for which occurs on or after completion of the exchange offer and will be deemed to have waived their rights to receive the accrued interest on the Old Notes.

In all cases, issuance of New Notes for Old Notes will be made only after timely receipt by the exchange agent of a timely book-entry confirmation of the Old Notes into the exchange agent's account at the book-entry transfer facility.

Unaccepted or non-exchanged Old Notes will be returned without expense to the tendering holder of the Old Notes. In the case of Old Notes tendered by book-entry transfer in accordance with the book-entry procedures described below, the non-exchanged Old Notes will be returned or recredited promptly.

Book-Entry Transfer

The exchange agent will make a request to establish an account for the Old Notes at DTC for purposes of the exchange offer within two business days after the date of this prospectus. A holder of the Old Notes must make book-entry delivery of Old Notes by causing DTC to transfer those Old Notes into the exchange agent's account at DTC in accordance with DTC's procedure for transfer. This holder should transmit its acceptance to DTC on or prior to the expiration date. DTC will verify this acceptance, execute a book-entry transfer of the tendered Old Notes into the exchange agent's account at DTC and then send to the exchange agent confirmation of this book-entry transfer. The confirmation of this book-entry transfer will include an agent's message confirming that DTC has received an express acknowledgment from this holder that this holder agrees to be bound by the assignment, transfer and exchange of the Old Notes. Delivery of New Notes issued in the exchange offer may be effected through book-entry transfer at DTC. However, an agent's message must be transmitted to and received by the exchange agent at the address listed below under " Exchange Agent" on or prior to the expiration date.

Exchanging Book-Entry Notes

The exchange agent and DTC have confirmed that any financial institution that is a participant in DTC may utilize DTC Automated Tender Offer Program, or ATOP, procedures to tender Old Notes. Any participant in the DTC may make book-entry delivery of Old Notes by causing the DTC to transfer such Old Notes into the exchange agent's account in accordance with the DTC's ATOP procedures for transfer. However, the exchange for the Old Notes so tendered will only be made after a book-entry confirmation of the book-entry transfer of Old Notes into the exchange agent's account, and timely receipt by the exchange agent of an agent's message.

Withdrawal Rights

Tenders of Old Notes may be withdrawn at any time before 5:00 p.m., New York City time, on the expiration date.

For a withdrawal to be effective, the exchange agent must receive a written notice of withdrawal at the address or at the facsimile number, indicated below under " Exchange Agent" before 5:00 p.m., New York City time, on the expiration date. Any notice of withdrawal must specify the number of the account at the DTC from which the Old Notes were tendered and specify the name and number of the account at the DTC to be credited with the withdrawn Old Notes and otherwise comply with the procedures of DTC.

We will determine all questions as to the validity, form and eligibility, including time of receipt, or notices of withdrawal. Any Old Notes so withdrawn will be deemed not to have been validly tendered for exchange. No New Notes will be issued unless the Old Notes so withdrawn are validly re-tendered. Any Old Notes that have been tendered for exchange, but which are not exchanged for any reason, will be credited to an account maintained with the DTC. Properly withdrawn Old Notes may be re-tendered by following the procedures described under " Procedures for Tendering" above at any time on or before 5:00 p.m., New York City time, on the expiration date.

Conditions to the Exchange Offer

Notwithstanding any other provision of the exchange offer, we shall not be required to accept for exchange, or to issue New Notes in exchange for, any Old Notes, and may terminate or amend the exchange offer, if at any time prior to the expiration date any of the following events occurs:

- there is threatened, instituted or pending any action or proceeding before, or any injunction, order or decree issued by, any court or governmental agency or other governmental regulatory or administrative agency or commission;

- a change in applicable law prohibits the consummation of such exchange offer; or

- any change, or any development involving a prospective change, has occurred or been threatened in our business, financial condition, operations or prospects and those of our subsidiaries taken as a whole that is or may be adverse to us, or we have become aware of facts that have or may have an adverse impact on the value of the Old Notes or the New Notes, which in our reasonable judgment in any case makes it inadvisable to proceed with the exchange offer and about which change or development we make a public announcement.

All conditions will be deemed satisfied or waived prior to the expiration date, unless we assert them prior to the expiration date. The foregoing conditions to the exchange offer are for our sole benefit and we may prior to the expiration date assert them regardless of the circumstances giving rise to any of these conditions, or we may prior to the expiration date waive them in whole or in part in our reasonable discretion. Our failure at any time to exercise any of the foregoing rights will not be deemed a waiver of any right.

In addition, we will not accept for exchange any Old Notes tendered, and no New Notes will be issued in exchange for any Old Notes, if at this time any stop order is threatened or in effect relating to the registration statement of which this prospectus constitutes a part. We are required to make every reasonable effort to obtain the withdrawal of any order suspending the effectiveness of a Registration Statement at the earliest possible moment.

Exchange Agent

We have appointed The Wells Fargo Bank, National Association as the exchange agent for the exchange offer. You should direct all executed letters, questions and requests for assistance, or requests for additional copies of this prospectus to the exchange agent addressed as follows:

Delivery To:
The Wells Fargo Bank, National Association
By Hand, Registered or Certified Mail, or Overnight Courier:
Wells Fargo Bank, National Association
707 Wilshire Boulevard, 17th Floor
Los Angeles, California 90017
Attn: Maddy Hall
For Information Call: (213) 614-2588
By Facsimile: (213) 614-3355
Confirm By Telephone: (213) 614-2588

All other questions should be addressed to Edison Mission Energy, 18101 Von Karman Avenue, Suite 1700, Irvine, California 92612, Attention: Steven D. Eisenberg. If you deliver the transmit instructions via facsimile other than to any facsimile number indicated above, then your delivery or transmission will not constitute a valid delivery or transmission.

Fees and Expenses

We will not make any payment to brokers, dealers or others soliciting acceptances of the exchange offer. We have agreed to pay all expenses incidental to the exchange offer other than commissions and concessions of any broker or dealer and certain transfer taxes and will indemnify holders of the notes, including any broker-dealers, against certain liabilities, including liabilities under the Securities Act. The estimated cash expenses to be incurred in connection with the exchange offer will be paid by us and will include fees and expenses of the exchange agent, accounting, legal, printing and related fees and expenses.

Accounting Treatment

We will not recognize any gain or loss for accounting purposes upon the consummation of the exchange offer. We will amortize the expense of the exchange offer over the term of the New Notes in accordance with accounting principles generally accepted in the United States of America.

Transfer Taxes

We will pay any transfer taxes in connection with the exchange of Old Notes for New Notes in the exchange offer unless you instruct us to register New Notes in the name of, or request any Old Notes not tendered or not accepted in the exchange offer be returned to, a person other than the registered tendering holder. In those cases, you will be responsible for the payment of any applicable transfer tax.

Consequences of Exchanging or Failing to Exchange the Old Notes

Holders of Old Notes who do not exchange their Old Notes for New Notes in the exchange offer will continue to be subject to the provisions in the Indenture regarding transfer and exchange of the Old Notes and the restrictions on transfer of the Old Notes as described in the legend on the Old Notes as a consequence of the issuance of the Old Notes under exemptions from, or in transactions not subject to, the registration requirements of the Securities Act and applicable state securities laws. In general, the Old Notes may not be offered or sold, unless registered under the Securities Act, except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. Old Notes holders that do not exchange Old Notes for New Notes in the exchange offer will no longer have any registration rights with respect to such notes.

Based on existing interpretations of the Securities Act by the SEC's staff contained in several no-action letters to third parties, and subject to the immediately following sentence, we believe that the New Notes would generally be freely transferable by holders after the exchange offer without further registration under the Securities Act, subject to certain representations required to be made by each holder of New Notes, as set forth below. However, any purchaser of New Notes who is one of our "affiliates" (as defined in Rule 405 under the Securities Act) or who intends to participate in the exchange offer for the purpose of distributing the New Notes:

- will not be able to rely on the applicable interpretation of the staff of the SEC;
- will not be able to tender its Old Notes in the exchange offer; and
- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the notes unless such sale or transfer is made pursuant to an exemption from such requirements. See "Plan of Distribution."

We do not intend to seek our own interpretation regarding the exchange offer and there can be no assurance that the SEC's staff would make a similar determination with respect to the notes as it has in other interpretations to other parties, although we have no reason to believe otherwise.

USE OF PROCEEDS

We will not receive any proceeds from the exchange offer. In consideration for issuing the New Notes, we will receive in exchange the Old Notes of like principal amount, the terms of which are identical in all material respects to the New Notes. The Old Notes surrendered in exchange for New Notes will be retired and canceled and cannot be reissued. Accordingly, issuance of the New Notes will not result in any increase in our indebtedness. We have agreed to bear the expenses of the exchange offer. No underwriter is being used in connection with the exchange offer.

CAPITALIZATION

The following table sets forth our consolidated capitalization as of June 30, 2007. This table should be read in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our financial statements and related notes included in this prospectus.

	As of June 30, 2007
Short- and long-term obligations(1)(2):	
Old Notes	$ 2,700
7.73% senior notes due 2009	13
7.50% senior notes due 2013	500
7.75% senior notes due 2016	500
Obligations to affiliates	78
EME recourse debt	3,791
Subsidiary debt obligations	166
Total consolidated debt	3,957
Shareholder's equity(3)	1,681
Total capitalization	$ 5,638

(1) Although not included in the table above, we are obligated under an intercompany loan with our subsidiary Midwest Generation to repay $1.4 billion of intercompany loans resulting from the Powerton and Joliet sale-leaseback transaction.

(2) As of June 30, 2007, we had $522 million available under our secured credit facility and our subsidiary, Midwest Generation, had $467 million available under its $500 million senior secured working capital facility.

(3) In connection with the early repayment of the 7.73% senior notes due 2009 and Midwest Generation's 8.75% second priority senior secured notes due 2034, tender premiums of $137 million, together with remaining deferred financing costs related to the debt repaid were expensed. The after-tax impact was approximately $98 million. In addition, we made a dividend payment of $899 million to our parent, MEHC, from the proceeds of the Old Notes enabling MEHC to repay its 13.50% senior secured notes due 2008, accrued interest and tender premiums related thereto.

SELECTED CONSOLIDATED FINANCIAL DATA

The following table sets forth a summary of our consolidated financial data for the periods indicated. In April 2006, EME received, as a capital contribution, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. These projects were previously owned by EME's affiliate, Edison Capital. EME accounted for this acquisition at Edison Capital's historical cost as a transaction between entities under common control for a net book value of approximately $76 million. The historical consolidated financial and operating results data reflects the acquisition as though EME had always owned the projects for all periods presented. The historical consolidated operating data for each of the three years ended December 31, 2006 and the financial position data as of December 31, 2006 and 2005 were derived from the audited historical consolidated financial statements included elsewhere in this prospectus. We derived the historical consolidated operating results data for the year ended December 31, 2003 and the financial position data as of December 31, 2004 from audited historical consolidated financial statements. We derived the historical consolidated operating results data for the year ended December 31, 2002 and the financial position data as of December 31, 2003 and 2002 from our accounting records. The following selected historical consolidated financial data as of June 30, 2007 and for the six months ended June 30, 2007 and 2006 has been derived from our unaudited consolidated financial statements included elsewhere in this prospectus. Our unaudited consolidated financial statements were prepared on a basis consistent with that used in preparing our audited consolidated financial statements and include all material adjustments, all of which are of a normal recurring nature, that, in the opinion of management, are necessary for a fair statement of our financial position and results of operations for the unaudited periods.

You should read the following information in conjunction with the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and the related notes included elsewhere in this prospectus. Historical results are not necessarily indicative of results that may be expected for any future period.

	Years Ended December 31,					Six Months Ended June 30,	
	2002	2003	2004	2005	2006	2006	2007
	(in millions)					(in millions) (unaudited)	
Income Statement Data							
Operating revenues	$ 1,713	$ 1,779	$ 1,653	$ 2,265	$ 2,239	$ 977	$ 1,243
Operating expenses							
Fuel, plant operations and plant operating lease	1,292	1,334	1,300	1,287	1,332	658	729
Loss on lease termination, asset impairment and other charges and credits	60	304	989	7		(5)	
Depreciation and amortization	147	156	152	134	144	71	76
Administrative and general	118	138	149	154	140	64	84
Total operating expenses	1,617	1,932	2,590	1,582	1,616	788	889
Operating income (loss)	96	(153)	(937)	683	623	189	354
Equity in income from unconsolidated affiliates	196	239	218	229	186	71	80
Impairment loss on equity method investment				(55)			
Interest and other income	15	2	52	69	120	61	57
Interest expense	(313)	(303)	(298)	(300)	(279)	(145)	(129)
Loss on early extinguishment of debt				(4)	(146)	(143)	(160)

	Years Ended December 31,					Six Months Ended June 30,	
	2002	2003	2004	2005	2006	2006	2007
	(in millions)					(in millions) (unaudited)	
Income (loss) from continuing operations before income taxes and minority interest	(6)	(215)	(965)	622	504	33	202
Provision (benefit) for income taxes	(28)	(121)	(406)	208	189	1	68
Minority interest	(2)	(2)	(1)		1		
Income (loss) from continuing operations	20	(96)	(560)	414	316	32	134
Income (loss) from operations of discontinued subsidiaries (including gain on disposal of $533 million in 2004), net of tax	22	124	690	29	98	77	5
Income before accounting change	42	28	130	443	414	109	139
Cumulative effect of change in accounting, net of tax(1)	(14)	(9)		(1)			
Net income	$ 28	$ 19	$ 130	$ 442	$ 414	$ 109	$ 139

(1) Our 2005 loss from a change in accounting principle resulted from the adoption of a new accounting standard for conditional asset retirements. Our 2003 loss from a change in accounting principle resulted from adoption of a new accounting standard for asset retirement obligations. Our 2002 loss from a change in accounting principle resulted from adoption of a new accounting standard for goodwill and other intangible assets.

	As of December 31,					As of June 30, 2007
	2002	2003(2)	2004(3)	2005	2006	
	(in millions)					(in millions) (unaudited)
Balance Sheet Data						
Assets	$ 11,220	$ 12,299	$ 7,087	$ 7,023	$ 7,250	$ 7,114
Current liabilities	1,356	1,203	994	846	646	504
Long-term obligations	3,022	2,919	3,530	3,330	3,035	3,845
Preferred securities	281					
Shareholder's equity	1,751	1,954	1,745	1,910	2,582	1,681

(2) In the fourth quarter of 2003, we adopted FIN No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51," which required us to reflect the junior subordinated deferrable debentures as a liability, which under the prior accounting treatment would have been eliminated in consolidation, instead of the Monthly Income Preferred Securities.

(3) Assets decreased in 2004 compared to 2003 due to completion of the sale of substantially all of our international assets.

	Years Ended December 31,					Six Months Ended June 30,	
	2002	2003	2004	2005	2006	2006	2007
	(in millions)					(in millions) (unaudited)	
Other Data							
Ratio of earnings to fixed charges(4)(5)	1.18x			2.23x	2.01x	1.20x	1.71x

(4) For purposes of computing the ratio of earnings to fixed charges, earnings are divided by fixed charges. "Earnings" represent the aggregate of income (loss) for continuing operations before income taxes and minority interest. "Fixed charges" represent interest (whether expensed or capitalized), dividends on preferred securities for continuing operations, amortization of debt discount and the interest component of rental expense.

(5) For the years ended December 31, 2004 and 2003, there was a fixed charge deficiency of $953 million and $85 million, respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Management's Discussion and Analysis of Financial Condition and Results of Operations is presented in four sections:

MANAGEMENT'S OVERVIEW; CRITICAL ACCOUNTING POLICIES

Management's Overview

Introduction

EME is a holding company which operates primarily through its subsidiaries and affiliates which are engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EME's subsidiaries or affiliates have typically been formed to own all or an interest in one or more power plants and ancillary facilities, with each plant or group of related plants being individually referred to by EME as a project. As of June 30, 2007, EME's subsidiaries and affiliates owned or leased interests in 32 operating power plants and 6 projects under construction.

EME's subsidiaries and affiliates have financed the development and construction or acquisition of its projects by capital contributions from EME and the incurrence of debt obligations by its subsidiaries and affiliates owning the operating facilities. These project level debt obligations are generally structured as non-recourse to EME, with several exceptions, including EME's guarantee of the Powerton and Joliet leases as part of a refinancing of indebtedness incurred by its project subsidiary to purchase the Illinois Plants. As a result, these project level debt obligations have structural priority with respect to revenues, cash flows and assets of the project companies over debt obligations incurred by EME itself. In this regard, EME has, itself, borrowed funds to make the equity contributions required of it for its projects and for general corporate purposes. Since EME does not, itself, directly own any revenue producing generation facilities, it depends for the most part on cash distributions from its projects to meet its debt service obligations, and to pay for general and administrative expenses. Distributions to EME from projects are generally only available after all current debt service obligations at the project level have been paid and are further restricted by contractual restrictions on distributions included in the documentation evidencing the project level debt obligations.

Business Strategy

EME's business strategy includes the following core elements:

- Optimizing the value of its existing generation assets through:
  - operational excellence focused on long-term cost effective maintenance;
  - integration of commercial marketing and trading activities with plant operations to enhance gross margin; and

- effective participation in regulatory rule-making in markets where EME operates.

Diversifying the fuel type of its generation assets through:

- developing and acquiring new renewable energy projects, primarily wind;
- developing and acquiring natural gas-fired power projects in locations where existing or projected capacity for generation is constrained; and
- developing new clean coal generation projects, such as integrated gasification combined cycle projects.

Entering into more mid- to long-term power sales contracts in order to complement its merchant sales activities.

Reducing cash flow volatility from merchant power plants through asset-based commodity hedging activities.

Leveraging the knowledge and expertise in trading to enhance financial performance within a disciplined risk management structure.

Business Development

EME has undertaken a number of activities in 2006 and 2007 with respect to wind projects, including the following:

Jointly completed development and commenced construction of six new wind projects with third parties, including:

- the 95 MW Sleeping Bear wind project located in Oklahoma,
- the 61 MW Mountain Wind I project located in Wyoming,
- the 50 MW Jeffers wind project located in Minnesota,
- the 38 MW Lookout wind project located in Pennsylvania,
- the 29 MW Forward wind project also located in Pennsylvania, and
- the 20 MW Odin wind project located in Minnesota.

Completed construction and commenced operations of the 161 MW Wildorado wind project located in Texas, the 15 MW Hardin wind project located in Iowa and the 21 MW Crosswinds wind project also located in Iowa.

During 2007, EME purchased 1,028 MW of turbines for delivery in 2008 and 2009 from Mitsubishi Power Systems Americas, Inc. and Suzlon Wind Energy Corporation with an aggregate purchase price of approximately $1.2 billion.

In April 2007, EME acquired six projects in development in Texas and Oklahoma totaling 700 MW. These projects are in various stages of development with target completion dates of 2008 through 2010. The purchase price for these projects is comprised of an initial payment and subsequent payments tied to milestones and adjustments based on EME's projected internal rate of return in individual projects. Completion of development of these projects is dependent on a number of items, including, among other things, obtaining power sales agreements, and in certain cases, permits and interconnection agreements.

In August 2007, EME acquired a 99.9% interest in a 150 MW wind project under development in Texas. The project consists of two phases. Construction of Phase I of this project (80 MW) commenced in August 2007 with completion scheduled during the first quarter of 2008. Phase II of this project (70 MW) is scheduled for completion during the fourth quarter of 2008. The total estimated capital cost, excluding capitalized interest, is approximately $266 million. The project plans to sell electricity into the Electric Reliability Council of Texas (ERCOT) market as a merchant wind generator.

As of June 30, 2007, EME had a development pipeline of potential wind projects with an installed capacity of approximately 3,100 MW (the development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive negotiation rights).

PJM Reliability Pricing Model

In April 2007, PJM Interconnection, LLC (PJM) completed the first capacity auction under the PJM Reliability Pricing Model. EME participated in the auction for the period June 1, 2007 through May 31, 2008. After accounting for previous forward sales of capacity, EME's subsidiary Edison Mission Marketing & Trading, Inc. (EMMT) sold net 2,628 MW of capacity from its fossil fuel plants located in Illinois (the Illinois Plants) and net 786 MW of capacity from the Homer City electric generating station in Pennsylvania (the Homer City facilities). The Illinois Plants and the Homer City facilities are located in the "Rest of Market" area which had a clearing price of $40.80 per MW-day.

In July 2007, EME participated in the auction for the period June 1, 2008 through May 31, 2009. After accounting for previous forward sales of capacity, EMMT sold net 3,283 MW of capacity from the Illinois Plants and net 820 MW of capacity from the Homer City facilities. The Illinois Plants and the Homer City facilities are located in the "Rest of Market" area which had a clearing price of $111.92 per MW-day.

For further discussion regarding the PJM and recent auctions, see "Market Risk Exposures Commodity Price Risk Capacity Price Risk."

Illinois Auction

In September 2006, the first Illinois power procurement auction was held by Commonwealth Edison according to the rules approved by the Illinois Commerce Commission. Through the auction, EMMT entered into two load requirements services contracts. Under the terms of these agreements, Midwest Generation expects to deliver, through EMMT, electricity, capacity and specified ancillary, transmission and load following services necessary to serve a portion of Commonwealth Edison's residential and small commercial customer load. The estimated megawatt-hours for the remainder of 2007, 2008 and 2009 under these energy supply agreements are 4.1 million, 5.6 million and 1.6 million, respectively. The amount of power sold under these agreements can vary significantly with variations in load. See "Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Illinois Plants" for further discussion of Midwest Generation's hedge position.

Illinois Settlement

On July 24, 2007, Midwest Generation and EMMT, along with other power generation companies and utilities, entered into a settlement agreement with the Illinois Attorney General. The settlement was subject to the passage of legislation which will, among other things, establish a new Illinois Power Agency to manage future power procurement for Commonwealth Edison and Ameren Corporation (Ameren) (beginning with the planning year June 1, 2009 through May 31, 2010). The settlement legislation was passed by the Illinois legislature on July 26, 2007, and was signed by the Governor of Illinois on August 28, 2007.

As part of the settlement, Midwest Generation has agreed to pay $25 million over three years toward approximately $1 billion in utility customer rate relief and startup costs of the new Illinois Power Agency. The remainder is to be funded by subsidiaries of Exelon Corporation, subsidiaries of Ameren, Dynegy Holdings Inc., and Mid-American Energy Company. Also as part of the settlement, the Illinois Attorney General has agreed to file motions to dismiss auction-related complaints filed at the Federal Energy Regulatory Commission (the FERC), the Illinois Commerce Commission and in the Illinois courts.

Subject to the foregoing, Midwest Generation plans to make a payment of $7.5 million within ten business days after the settlement becomes effective (or on such later date as the Illinois Attorney General may specify in writing), followed by monthly payments of $750,000 beginning in January 2008 and continuing until the total commitment has been funded. These payments are non-refundable; however, Midwest Generation's obligations to make the monthly payments will cease if, at any time prior to December 2009, as further described in the rate relief package and related agreements, Illinois imposes an electric rate freeze or an additional tax on generators.

Environmental Developments Regarding Emissions

On December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, nitrogen oxide (NOx) and sulfur dioxide (SO2) emissions at Midwest Generation's Illinois coal-fired power plants, which Midwest Generation believes will provide reasonable certainty of the timing and amount of emissions reductions which will be required of the Illinois Plants for these pollutants through 2018. The agreement requires Midwest Generation to achieve specified emissions reductions through a combination of environmental retrofits or unit shutdowns. Capital expenditures are estimated (in 2006 dollars) between $2.7 billion and $3.4 billion. See "Liquidity and Capital Resources Environmental Matters and Regulations Air Quality Regulation Clean Air Act Illinois" for further discussion.

Refinancing

Senior Notes Offering

On June 6, 2006, EME completed a private offering of $500 million of its 7.50% senior notes due 2013 and $500 million of its 7.75% senior notes due 2016. The proceeds of the offering were used, together with cash on hand, to purchase substantially all of EME's outstanding 10% senior notes due 2008 and 9.875% senior notes due 2011. On December 6, 2006, EME redeemed all of its remaining 10% senior notes and 9.875% senior notes outstanding. In connection with the purchase of these notes, EME recorded a $146 million loss on early extinguishment of debt in 2006.

On May 7, 2007, EME completed a private offering of $1.2 billion of its 7.00% senior notes due May 15, 2017, $800 million of its 7.20% senior notes due May 15, 2019 and $700 million of its 7.625%

senior notes due May 15, 2027. EME will pay interest on the senior notes on May 15 and November 15 of each year, beginning on November 15, 2007. The net proceeds were used, together with cash on hand, to:

- purchase substantially all of EME's outstanding 7.73% senior notes due 2009,
- purchase substantially all of Midwest Generation's 8.75% second priority senior secured notes due 2034,
- repay the outstanding balance of Midwest Generation's senior secured term loan facility ($327.8 million), and
- make a dividend payment of $899 million to MEHC which enabled MEHC to purchase substantially all of its 13.5% senior secured notes due 2008.

Redemption of MEHC Senior Secured Notes

On June 25, 2007, MEHC redeemed in full its senior secured notes. As a result of the redemption, EME is no longer subject to financial and investment restrictions that were contained in the indenture pursuant to which the senior secured notes were issued. Following the redemption, MEHC no longer files reports with the SEC.

The refinancing activities improved EME's overall liquidity, operating flexibility and ability to capitalize on growth opportunities. EME recorded a total pre-tax loss of approximately $160 million (approximately $98 million after tax) on early extinguishment of debt during the second quarter of 2007.

Credit Agreement Amendments

During the second quarter of 2007, EME amended its existing $500 million secured credit facility, increasing the total borrowings available thereunder to $600 million, and Midwest Generation amended and restated its existing $500 million senior secured working capital facility. The changes to the senior secured working capital facility included a reduction in the interest rate, a longer maturity date, and fewer restrictive covenants. Midwest Generation intends to use its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation may also support its hedging activities by granting first or second priority liens to eligible hedge counterparties.

ERP Initiative

During 2006, EME commenced a new initiative as part of an Edison International enterprise-wide project to implement an integrated enterprise resource planning (ERP) application from SAP during the next two years. The implementation of this application will replace EME's existing financial, human resources, materials management, and fuel management information systems with SAP's integrated ERP application. The procurement and material management systems were implemented for three of the Illinois Plants in July 2007, as well as the EME financial systems. Implementation of these applications at the remaining Illinois Plants and Homer City facilities began on September 1, 2007, and implementation of the human resources systems is scheduled for the second quarter of 2008 as part of an Edison International enterprise-wide project.

Critical Accounting Policies

Introduction

The accounting policies described below are viewed by management as "critical" because their correct application requires the use of material judgments and estimates, and they have a material impact on EME's results of operations and financial position.

Derivative Financial Instruments and Hedging Activities

EME uses derivative financial instruments for hedging activities and trading purposes. Derivative financial instruments are mainly utilized to manage exposure from changes in electricity and fuel prices and interest rates. EME follows Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), which requires derivative financial instruments to be recorded at their fair value unless an exception applies. SFAS No. 133 also requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for hedge accounting, depending on the nature of the hedge, changes in fair value are either offset by changes in the fair value of the hedged assets, liabilities or firm commitments through earnings, or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of a derivative's change in fair value is immediately recognized in earnings. For further discussion, see "Market Risk Exposures Accounting for Energy Contracts."

Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment. The majority of EME's long-term power sales and fuel supply agreements related to its generation activities either: (1) do not meet the definition of a derivative because they are not readily convertible to cash, or (2) qualify as normal purchases and sales and are, therefore, recorded on an accrual basis.

Derivative financial instruments used for trading purposes include forwards, futures, options, swaps and other financial instruments with third parties. EME records derivative financial instruments used for trading at fair value. The majority of EME's derivative financial instruments with a short-term duration (less than one year) are valued using quoted market prices. In the absence of quoted market prices, derivative financial instruments are valued considering the time value of money, volatility of the underlying commodity, and other factors as determined by EME. Resulting gains and losses are recognized in operating revenues in the accompanying consolidated income statements in the period of change. Derivative assets include open financial positions related to derivative financial instruments recorded at fair value, including cash flow hedges, that are "in-the-money" and the present value of net amounts receivable from structured transactions. Derivative liabilities include open financial positions related to derivative financial instruments, including cash flow hedges, that are "out-of-the-money."

Determining the fair value of derivatives under SFAS No. 133 is a critical accounting policy because the fair value of a derivative is susceptible to significant change resulting from a number of factors, including: volatility of energy prices, credit risks, market liquidity and discount rates. See "Market Risk Exposures," for a description of risk management activities and sensitivities to change in market prices.

EME enters into master agreements and other arrangements in conducting hedging and trading activities with a right of setoff in the event of bankruptcy or default by the counterparty. These types of transactions are reported net in the balance sheet in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 39, "Offsetting Amounts Related to Certain Contracts."

Impairment of Long-Lived Assets

EME follows SFAS No. 144. EME evaluates long-lived assets whenever indicators of impairment exist. This accounting standard requires that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

The assessment of impairment is a critical accounting policy because significant management judgment is required to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors that EME considers important, which could trigger an impairment, include operating losses from a project, projected future operating losses, the financial condition of counterparties, or significant negative industry or economic trends. During 2005 and 2004, EME recorded impairment charges of $55 million and $35 million, respectively, related to specific assets included in continuing operations. See "Results of Operations Annual Results of Continuing Operations for 2006, 2005 and 2004 Earnings from Consolidated Operations Illinois Plants" and " Earnings from Unconsolidated Affiliates Impairment Loss on Equity Method Investment."

Off-Balance Sheet Financing

EME has entered into sale-leaseback transactions related to the Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania. See "Liquidity and Capital Resources Contractual Obligations, Commitments and Contingencies Contractual Obligations at December 31, 2006 Operating Lease Obligations." Each of these transactions was completed and accounted for by EME as an operating lease in its consolidated financial statements in accordance with SFAS No. 98, which requires, among other things, that all the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. The sale-leaseback transactions of these power plants were complex matters that involved management judgment to determine compliance with SFAS No. 98, including the transfer of all the risk and rewards of ownership of the power plants to the new owner without EME's continuing involvement other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. Each of these leases uses special purpose entities.

Based on existing accounting guidance, EME does not record these lease obligations in its consolidated balance sheet. If these transactions were required to be consolidated as a result of future changes in accounting guidance, it would: (1) increase property, plant and equipment and long-term obligations in the consolidated financial position, and (2) impact the pattern of expense recognition related to these obligations because EME would likely change from its current straight-line recognition of rental expense to an annual recognition of the straight-line depreciation on the leased assets as well as the interest component of the financings which is weighted more heavily toward the early years of the obligations. The difference in expense recognition would not affect EME's cash flows under these transactions. See "Liquidity and Capital Resources Off-Balance Sheet Transactions Sale-Leaseback Transactions."

Contract Indemnities

During 2004, EME sold a majority of its international operations. The asset sale agreements contain indemnities from EME to the purchasers, including indemnification for pre-closing environmental liabilities and for pre-closing foreign taxes imposed with respect to operations of the assets prior to the sale. At June 30, 2007, EME had recorded an estimated liability of $94 million related to these matters.

In addition, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation Company, LLC (Exelon Generation) for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in a supplemental agreement. See "Liquidity and Capital Resources Contractual Obligations, Commitments and Contingencies Commercial Commitments." Midwest Generation engaged an independent actuary during 2004 with extensive experience in performing asbestos studies to estimate future losses based on its claims experience and other available information. In calculating future losses, the actuary made various assumptions, including, but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that the filing date of asbestos claims will not be after 2045. At June 30, 2007, Midwest Generation had recorded a liability of $64 million related to this contract indemnity.

Income Taxes

SFAS No. 109, "Accounting for Income Taxes," requires the asset and liability approach for financial accounting and reporting for deferred income taxes. EME uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. See "Audited Consolidated Financial Statements of Edison Mission Energy Notes to Consolidated Financial Statements Note 10. Income Taxes" for additional details.

As part of the process of preparing its consolidated financial statements, EME is required to estimate its income taxes in each jurisdiction in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within EME's consolidated balance sheet. In addition, estimated taxes for uncertain tax positions are accrued and included in other long-term liabilities in the consolidated balance sheet.

For additional information regarding EME's accounting policies, see "Audited Consolidated Financial Statements of Edison Mission Energy Notes to Consolidated Financial Statements Note 1. Summary of Significant Accounting Policies."

RESULTS OF OPERATIONS

EME operates in one line of business, independent power production. Operating revenues are primarily derived from the sale of power generated from the Illinois Plants and the Homer City facilities. Intercompany interest expense and income between EME and its consolidated subsidiaries have been eliminated in the following project results, except as described below with respect to loans provided to EME from a wholly owned subsidiary, Midwest Generation, and loans from Midwest Generation to EMMT for margining. Equity in income from unconsolidated affiliates relates to energy projects accounted for under the equity method. EME recognizes its proportional share of the income or loss of such entities.

On April 1, 2006, EME received, as a capital contribution, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. These projects were previously owned by EME's affiliate, Edison Capital. Both MEHC and Edison Capital are wholly owned subsidiaries of Edison Mission Group, which is a subsidiary of Edison International. EME accounted for this acquisition at Edison Capital's historical cost as a transaction between entities under common control. Therefore, these consolidated financial statements include the results of operations, financial position and cash flows of the acquired projects as though EME had such ownership throughout the periods presented.

EME uses the words "earnings" or "losses" in this section to describe income or loss from continuing operations before income taxes.

Interim Results of Continuing Operations

The following section provides a summary of the operating results for the second quarters of 2007 and 2006 and six months ended June 30, 2007 and 2006 together with discussions of the contributions by specific projects and of other significant factors affecting these results.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in millions)			
Project Earnings (Losses) Before Income Taxes(1)				
Consolidated operations				
Illinois Plants	$ 88	$ 25	$ 277	$ 152
Homer City	38	35	102	33
Energy Trading(2)	36	26	62	55
San Juan Mesa	1	1	3	5
Gain on sale of assets				4
Storm Lake	2	3	4	3
Wildorado	2		2	
Other	1	(1)	3	
Unconsolidated affiliates				
Big 4 projects	45	32	63	55
Sunrise	6	5	4	3
Doga	10	5	14	4
Other	4	2	9	3
	233	133	543	317
Corporate interest income	18	20	38	37
Corporate interest expense	(81)	(64)	(136)	(130)
Corporate administrative and general	(36)	(25)	(68)	(49)
Loss on early extinguishment of debt	(160)	(143)	(160)	(143)
Other income (expense), net	(2)		(3)	10
	$ (28)	$ (79)	$ 214	$ 42

(1) Project earnings are equal to income from continuing operations before income taxes, except with respect to wind projects, which also include production tax credits. Wind project earnings, including the production tax credits set forth in the table below, were $6 million and $4 million for the second quarters of 2007 and 2006, respectively, and $11 million and $9 million for the six months ended June 30, 2007 and 2006, respectively. The project earnings for the wind projects include $7 million and $4 million of production tax credits for the second quarters of 2007 and 2006, respectively, and $12 million and $9 million for the six months ended June 30, 2007 and 2006, respectively. Production tax credits are recognized as wind energy is generated based upon a per kilowatt-hour rate prescribed in applicable federal and state statutes. Under generally accepted accounting principles (GAAP), production tax credits generated by the wind projects are recorded as a reduction in income taxes. Accordingly, project earnings (losses) represent a non-GAAP performance measure which may not be comparable to those of other companies. Management believes that inclusion of production tax credits in project earnings for wind projects is more meaningful for investors as federal and state subsidies are an integral part of the economics of these projects. The following table reconciles the total project earnings as shown above with income from continuing operations before income taxes under GAAP:

	Three Months Ended June 30,		Six Months Ended June 30	
	2007	2006	2007	2006

	Three Months Ended June 30,		Six Months Ended June 30	
	(in millions)			
Project earnings (losses)	$ (28)	$ (79)	$ 214	$ 42
Less: Production tax credits	(7)	(4)	(12)	(9)
Income (loss) from continuing operations before income taxes	$ (35)	$ (83)	$ 202	$ 33

(2) Income from energy trading represents the gains recognized from price changes related to contracts for electricity, fuels and transmission congestion. The overhead cost of energy trading is included in administrative and general expenses.

Earnings from Consolidated Operations

Illinois Plants

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in millions)			
Operating Revenues	$ 334	$ 266	$ 765	$ 612
Operating Expenses				
Fuel	85	72	194	166
Gain on sale of emission allowances(1)			(4)	(6)
Plant operations	127	115	216	196
Plant operating leases	18	18	37	37
Depreciation and amortization	25	25	50	50
Loss from disposal of assets	1		1	
Administrative and general	6	7	11	12
Total operating expenses	262	237	505	455
Operating Income	72	29	260	157
Other Income (Expense)				
Interest income on note receivable from EME	28	28	56	56
Interest expense and other	(12)	(32)	(39)	(61)
Total other income (expense)	16	(4)	17	(5)
Income Before Taxes	$ 88	$ 25	$ 277	$ 152
Statistics				
Generation (in GWh)				
Energy only contracts	4,445	5,493	11,143	12,738
Load requirements services contracts(2)	1,681		3,613	
Total	6,126	5,493	14,756	12,738
Aggregate plant performance				
Equivalent availability(3)	61.5%	66.0%	74.7%	76.4%
Capacity factor(4)	50.0%	44.8%	60.5%	52.3%
Load factor(5)	81.3%	67.9%	81.1%	68.4%
Forced outage rate(6)	6.0%	7.7%	6.0%	5.0%
Average realized price/MWh				
Energy only contracts(7)	$ 49.04	$ 46.70	$ 49.06	$ 45.85
Load requirements services contracts(8)	$ 62.58	$	$ 62.21	$
Capacity revenue only (in millions)	$ 4	$ 7	$ 6	$ 13
Average fuel costs/MWh	$ 13.82	$ 13.42	$ 13.13	$ 13.14

(1) The Illinois Plants sold excess SO2 emission allowances to the Homer City facilities at fair market value. Sales to the Homer City facilities were $10 million for both the quarter ended and six months ended June 30, 2007. These sales reduced operating expenses. EME eliminated $8 million of intercompany profit during the second quarter of 2007 on emission allowances sold but not yet used by the Homer City facilities at June 30, 2007. In addition, EME recorded $4 million and $6 million of intercompany profit during the first quarters of 2007 and 2006, respectively, on emission allowances sold by the Illinois Plants to the Homer City facilities in the fourth quarters of 2006 and 2005, respectively, but not used by the Homer City facilities until the first quarters of 2007 and 2006, respectively.

(2) Represents two load requirements services contracts, awarded as part of an Illinois auction, with Commonwealth Edison that commenced on January 1, 2007.

(3) The equivalent availability factor is defined as the number of MWh the coal units are available to generate electricity divided by the product of the capacity of the coal units (in MW) and the number of hours in the period. Equivalent availability reflects the impact of the unit's inability to achieve full load, referred to as derating, as well as outages which result in a complete unit shutdown. The coal units are not available during periods of planned and unplanned maintenance.

(4) The capacity factor is defined as the actual number of MWh generated by the coal plants divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period.

(5) The load factor is determined by dividing capacity factor by the equivalent availability factor.

(6) Midwest Generation refers to unplanned maintenance as a forced outage.

(7) The average realized energy price reflects the average price at which energy is sold into the market including the effects of hedges, real-time and day-ahead sales and PJM fees and ancillary services. It is determined by dividing (i) operating revenue less unrealized SFAS No. 133 gains (losses) and other non-energy related revenue by (ii) generation. Revenue related to capacity sales are excluded from the calculation of average realized energy price.

(8) The average realized price reflects the contract price for sales to Commonwealth Edison under load requirements services contracts that include energy, capacity and ancillary services. It is determined by dividing (i) contract revenue less PJM operating and ancillary charges by (ii) generation.

Earnings from the Illinois Plants increased $63 million and $125 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The increases in earnings were primarily due to higher energy revenues resulting from higher generation and average realized energy prices as compared to 2006 and lower interest expense due to the repayment of debt in May 2007. Partially offsetting these increases were higher planned maintenance costs. Earnings for the six months ended June 30, 2007 were also adversely affected by an increase in unrealized losses in 2007 related to hedge contracts described below.

Included in operating revenues were unrealized gains (losses) of $4 million and $1 million for the second quarters of 2007 and 2006, respectively, and $(18) million and $11 million for the six months ended June 30, 2007 and 2006, respectively. Unrealized gains (losses) are primarily due to power contracts that did not qualify for hedge accounting under SFAS No. 133 (sometimes referred to as economic hedges). These energy contracts were entered into to hedge the price risk related to projected sales of power. During 2007, power prices increased, resulting in mark-to-market losses on economic hedges. At June 30, 2007, unrealized losses of $11 million were recognized primarily from economic hedges related to subsequent periods. See "Market Risk Exposures Commodity Price Risk" for more information regarding forward market prices.

The earnings of the Illinois Plants included interest income of $28 million for both the second quarters of 2007 and 2006 and $56 million for both the six months ended June 30, 2007 and 2006 related to loans to EME. In August 2000, Midwest Generation, which owns or leases the Illinois Plants, entered into a sale-leaseback transaction of the Powerton-Joliet facilities. The proceeds from the sale of these facilities were loaned to EME, which also provided a guarantee of the related lease obligations of Midwest Generation. The Powerton-Joliet sale-leaseback is recorded as an operating lease for accounting purposes.

Homer City

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
		(in millions)		
Operating Revenues	$ 176	$ 151	$ 374	$ 274
Operating Expenses				
Fuel(1)	68	68	140	129
Gain on sale of emission allowances(2)				
Plant operations	41	28	75	63
Plant operating leases	26	26	51	51
Depreciation and amortization	4	4	7	8
Administrative and general	1	1	2	2
Total operating expenses	140	127	275	253
Operating Income	36	24	99	21
Other Income (Expense)				
Interest and other income	2	12	4	13
Interest expense		(1)	(1)	(1)
Total other income	2	11	3	12
Income Before Taxes	$ 38	$ 35	$ 102	$ 33
Statistics				
Generation (in GWh)	3,160	2,866	6,453	5,387
Aggregate plant performance				
Equivalent availability(3)	83.5%	74.3%	85.0%	73.1%
Capacity factor(4)	76.7%	69.5%	78.7%	65.7%
Load factor(5)	91.8%	93.6%	92.6%	89.9%
Forced outage rate(6)	1.8%	19.9%	3.9%	22.8%
Average realized energy price/MWh(7)	$ 54.32	$ 47.38	$ 56.13	$ 48.41
Capacity revenue only (in millions)	$ 7	$ 4	$ 13	$ 6
Average fuel costs/MWh	$ 21.62	$ 24.13	$ 21.72	$ 24.03

(1) Included in fuel costs were $6 million and $9 million during the second quarters of 2007 and 2006, respectively, and $12 million and $21 million during the six months ended June 30, 2007 and 2006, respectively, related to the net cost of SO2 emission allowances. See "Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk" for more information regarding the price of SO2 allowances.

(2) The Homer City facilities sold excess NOX emission allowances to the Illinois Plants at fair market value. Sales to the Illinois Plants were $6 million in the first quarter of 2006. These sales reduced operating expenses. EME eliminated the intercompany transaction for emission allowances sold but not yet used by the Illinois Plants at June 30, 2006.

(3) The equivalent availability factor is defined as the number of MWh the coal units are available to generate electricity divided by the product of the capacity of the coal units (in MW) and the number of hours in the period. Equivalent availability reflects the impact of the unit's inability to achieve full load, referred to as derating, as well as outages which result in a complete unit shutdown. The coal units are not available during periods of planned and unplanned maintenance.

(4) The capacity factor is defined as the actual number of MWh generated by the coal plants divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period.

(5) The load factor is determined by dividing capacity factor by the equivalent availability factor.

(6) Homer City refers to unplanned maintenance as a forced outage.

(7) The average realized energy price reflects the average price at which energy is sold into the market including the effects of hedges, real-time and day-ahead sales and PJM fees and ancillary services. It is determined by dividing (i) operating revenue less unrealized SFAS No. 133 gains (losses) and other non-energy related revenue by (ii) total generation.

Earnings from Homer City increased $3 million and $69 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The increases in earnings were primarily attributable to higher generation and average realized energy prices and lower SO2 emission allowances as compared to 2006. Partially offsetting these increases were higher maintenance costs in 2007 related to the planned outage at Unit 2 of the Homer City facilities and estimated insurance recovery of approximately $11 million related to the Unit 3 outage recorded during the second quarter of 2006 reflected in other income (expense), net in EME's consolidated statements of income (loss). The Unit 3 outage reduced the amount of generation during the six-month period ended June 30, 2006.

Included in operating revenues were unrealized gains (losses) from hedging activities of $(3) million and $9 million for the second quarters of 2007 and 2006, respectively, and $(2) million and $4 million for six months ended June 30, 2007 and 2006, respectively. Unrealized gains (losses) were primarily attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges under SFAS No. 133. The ineffective portion of hedge contracts at Homer City was primarily attributable to changes in the difference between energy prices at PJM West Hub (the settlement point under forward contracts) and the energy prices at the Homer City busbar (the delivery point where power generated by the Homer City facilities is delivered into the transmission system). At June 30, 2007, unrealized losses of $13 million were recognized primarily from the ineffective portion of cash flow hedges related to subsequent periods. See "Market Risk Exposures Commodity Price Risk" for more information regarding forward market prices.

Homer City Unit 3 Outage

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed resulting in a suspension of operations at this unit. Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. The main transformer failure resulted in claims under Homer City's property and business interruption insurance policies. At June 30, 2007, Homer City had recorded a $13 million receivable related to these claims. Resolution of the claims is subject to a number of uncertainties, including computations of the lost profit during the outage period.

Energy Trading

EME seeks to generate profit by utilizing its subsidiary, EMMT, to engage in trading activities in those markets in which it is active as a result of its management of the merchant power plants of Midwest Generation and Homer City. EMMT trades power, fuel and transmission congestion primarily in the eastern power grid using products available over the counter, through exchanges and from ISOs. Earnings from energy trading activities increased $10 million and $7 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The increase in earnings from energy trading activities was partially attributable to gains on capacity transactions.

San Juan Mesa

Earnings from the San Juan Mesa wind project decreased $2 million for the six months ended June 30, 2007, compared to the corresponding period of 2006. The year-to-date decline in earnings was primarily due to a decrease in EME's ownership interest of the San Juan Mesa wind project to 75% from 100% in March 2006. During the first quarter of 2006, EME completed the sale of 25% of its ownership interest in the San Juan Mesa wind project to Citi Renewable Investments I LLC, a wholly owned subsidiary of Citicorp North America, Inc. Proceeds from the sale were $43 million. EME recorded a pre-tax gain on the sale of approximately $4 million during the first quarter of 2006.

Wildorado

Earnings from the Wildorado wind project were $2 million for both the second quarter of 2007 and six months ended June 30, 2007. EME had no comparable results from the Wildorado wind project in 2006. Commercial operation of the Wildorado wind project commenced during April 2007.

Earnings from Unconsolidated Affiliates

Big 4 Projects

Earnings from the Big 4 projects increased $13 million and $8 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The increases in earnings were primarily due to payments received in settlement of claims related to the natural gas purchase contracts during the second quarter of 2007 and a planned outage at the Sycamore Cogeneration plant during the second quarter of 2006. Partially offsetting these increases were lower volumes sold in 2007 for the Kern River project.

The earnings from the Big 4 projects included interest expense from Edison Mission Energy Funding of $1 million for both the second quarters of 2007 and 2006 and $2 million and $3 million for the six months ended June 30, 2007 and 2006, respectively.

Doga

Earnings from the Doga project increased $5 million and $10 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The increases in earnings were primarily due to the recognition of distributions received from the Doga project. Effective March 31, 2007, EME accounted for its ownership in the Doga project on the cost method (earnings are recognized as cash is distributed from the project).

Other

Earnings from other unconsolidated affiliates increased $2 million and $6 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The 2007 increases in earnings were attributable to an increase in earnings from the Westside projects primarily due to payments received in settlement of claims related to the natural gas purchase contracts and lower maintenance expense, partially offset by lower steam and energy prices.

Corporate Interest Expense

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in millions)			
Interest expense to third parties	$ 53	$ 36	$ 79	$ 74
Interest expense to Midwest Generation(1)	28	28	57	56
Total corporate interest expense	$ 81	$ 64	$ 136	$ 130

(1) Includes interest expense of EMMT related to loans from Midwest Generation for margining.

Interest Expense to Third Parties

EME's interest expense to third parties increased $17 million and $5 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The increase was primarily attributable to $2.7 billion of new debt entered into by EME as part of its refinancing activities in May 2007. Partially offsetting this increase was an increase in capitalized interest of $4 million and $10 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, due to wind projects under construction.

Corporate Administrative and General Expenses

Administrative and general expenses increased $11 million and $19 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The increase was primarily due to higher development costs incurred in 2007 (mostly related to wind projects) and higher performance-based compensation. See "Management's Overview; Critical Accounting Policies Management's Overview."

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt was $160 million for the second quarter of 2007 and six months ended June 30, 2007 related to the early repayment of EME's 7.73% senior notes due June 15, 2009 and Midwest Generation's 8.75% second priority senior secured notes due May 1, 2034. Loss on early extinguishment of debt was $143 million for the second quarter of 2006 and six months ended June 30, 2006 related to the early repayment of EME's 10% senior notes due August 15, 2008 and 9.875% senior notes due April 15, 2011.

Other Income (Expense), Net

Other income (expense), net decreased $2 million and $13 million for the second quarter of 2007 and six months ended June 30, 2007, respectively, compared to the corresponding periods of 2006. The 2007 year-to-date decrease was partially attributable to an $8 million gain related to receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter of 2006.

Income Taxes

EME's income tax provision from continuing operations was $68 million and $1 million for the six months ended June 30, 2007 and 2006, respectively. Income tax benefits are recognized pursuant to a tax-allocation agreement with Edison International. See "Liquidity and Capital Resources EME's Liquidity as a Holding Company Intercompany Tax-Allocation Agreement." During the six months ended June 30, 2007 and 2006, EME recognized $12 million and $9 million, respectively, of production tax credits related to wind projects and $7 million and $3 million, respectively, related to estimated state income tax benefits allocated from Edison International.

Interim Results of Discontinued Operations

Income from discontinued operations, net of tax, was $2 million and $4 million for the second quarters of 2007 and 2006, respectively, and $5 million and $77 million during the first six months of 2007 and 2006, respectively, largely attributable to distributions received from the Lakeland project, discussed below.

Lakeland Project

EME previously owned a 220 MW power plant located in the United Kingdom, referred to as the Lakeland project. An administrative receiver was appointed in 2002 as a result of default by the project's counterparty, a subsidiary of TXU Europe Group plc. Following a claim for termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims have been settled, EME received payments of £61 million (approximately $106 million) in the first quarter of 2006, £9 million (approximately $16 million) in April 2006 and £4 million (approximately $8 million) in January 2007. The after-tax income attributable to the Lakeland project was none and $10 million for the second quarters of 2007 and 2006, respectively, and $5 million and $83 million for the six months ended June 30, 2007 and 2006, respectively. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounts for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

Annual Results of Continuing Operations for 2006, 2005 and 2004

The following section provides a summary of the operating results for the three years ended December 31, 2006 together with discussions of the contributions by specific projects and of other significant factors affecting these results.

	Years Ended December 31,		
	2006	**2005**	**2004**
		(in millions)	
Project Earnings (Losses) Before Income Taxes(1)			
Consolidated operations			
Illinois Plants	$ 459	$ 547	$ (881)
Homer City	156	74	77
Energy Trading(2)	130	195	23
Doga(3)			6
San Juan Mesa	7		
Gain on sale of assets	4		
Storm Lake	5	2	8
Other		(1)	4
Unconsolidated affiliates			
Big 4 projects	132	158	142
Sunrise	34	29	28
March Point		9	17
Impairment loss on equity method investment		(55)	
Doga	1	7	1
Other	12	13	12
	940	978	(563)
Corporate interest income	82	55	6
Corporate interest expense	(253)	(270)	(283)
Corporate administrative and general	(113)	(126)	(150)
Gain on sale of investments			43
Loss on early extinguishment of debt	(146)	(4)	
Other income (expense), net	10	(3)	(11)
	$ 520	$ 630	$ (958)

(1) Project earnings are equal to income from continuing operations before income taxes, except with respect to wind projects, which also include production tax credits. Wind project earnings, including production tax credits set forth in the table below, were $13 million, $4 million and $10 million for the years ended December 31, 2006, 2005 and 2004, respectively. The

project earnings for the wind projects include $16 million, $8 million and $7 million of production tax credits for the years ended December 31, 2006, 2005 and 2004, respectively. Production tax credits are recognized as wind energy is generated based upon a per kilowatt-hour rate prescribed in applicable federal and state statutes. Under GAAP, production tax credits generated by the wind projects are recorded as a reduction in income taxes. Accordingly, project earnings (losses) represent a non-GAAP performance measure which may not be comparable to those of other companies. Management believes that inclusion of production tax credits in project earnings for wind projects is more meaningful for investors as federal and state subsidies are an integral part of the economics of these projects. The following table reconciles the total project earnings as shown above with income from continuing operations before income taxes and minority interest under GAAP:

	Years Ended December 31,		
	2006	**2005**	**2004**
		(in millions)	
Project earnings (losses)	$ 520	$ 630	$ (958)
Less: Production tax credits	(16)	(8)	(7)
Income (loss) from continuing operations before income taxes and minority interest	$ 504	$ 622	$ (965)

(2) Income from energy trading represents the gains recognized from price changes associated with the purchase and sale of contracts for electricity, fuels and transmission. The overhead cost of energy trading is included in administrative and general expenses.

(3) Income before taxes of Doga represents both EME's 80% ownership interest and the ownership interests of minority interest holders on a calendar year basis. The interests of minority shareholders in the after-tax earnings of Doga are reflected in a separate line item in the consolidated statements of income.

Earnings from Consolidated Operations

Illinois Plants

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Operating Revenues	$ 1,399	$ 1,429	$ 1,058
Operating Expenses			
Fuel(1)	382	383	408
Gain on sale of emission allowances(2)	(16)	(56)	(26)
Plant operations	369	351	379
Plant operating leases	75	75	84
Depreciation and amortization	101	99	116
Loss on lease termination, asset impairment and other charges	4	7	989
Administrative and general	19	19	1
Total operating expenses	934	878	1,951
Operating Income (Loss)	465	551	(893)
Other Income (Expense)			
Interest income from note receivable from EME	115	113	113
Interest expense and other	(121)	(117)	(101)
Total other income (expense)	(6)	(4)	12
Income (Loss) Before Taxes	$ 459	$ 547	$ (881)
Statistics			
Generation (in GWh):			
Merchant	28,898	30,953	17,133
Power purchase agreement			13,435
Total coal-fired generation	28,898	30,953	30,568
Equivalent availability(3)	79.3%	79.6%	84.4%
Capacity factor(4)	58.8%	63.0%	65.3%
Load factor(5)	74.1%	79.1%	77.4%
Forced outage rate(6)	7.9%	7.8%	5.4%
Average realized energy price/MWh(7):			
Merchant	$ 46.19	$ 45.55	$ 31.20
Power purchase agreement	$	$	$ 17.60
Total coal-fired generation(8)	$ 46.19	$ 45.55	$ 25.22
Capacity revenue only (in millions)	$ 24	$ 27	$ 289
Average fuel costs/MWh	$ 13.19	$ 12.40	$ 11.60

(1) The Illinois Plants purchased NOx emission allowances from the Homer City facilities at fair market value. Purchases were $6 million in 2006, $5 million in 2005 and none in 2004. These purchases are included in fuel costs.

(2)

The Illinois Plants sold excess SO_2 emission allowances to the Homer City facilities at fair market value. Sales to the Homer City facilities were $14 million in 2006, $61 million in 2005 and $26 million in 2004. These sales reduced operating expenses. EME recorded $6 million of intercompany profit during the first quarter of 2006 that was eliminated by EME in 2005 on emission allowances sold by the Illinois Plants to the Homer City facilities in the fourth quarter of 2005 but not used by the Homer City facilities until the first quarter of 2006. In addition, EME eliminated $4 million of intercompany profit during the fourth quarter of 2006 on emission allowances sold but not yet used by the Homer City facilities at December 31, 2006.

(3) The equivalent availability factor is defined as the number of megawatt-hours the coal plants are available to generate electricity divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period. Equivalent availability reflects the impact of the unit's inability to achieve full load, referred to as derating, as well as outages which result in a complete unit shutdown. The coal plants are not available during periods of planned and unplanned maintenance.

(4) The capacity factor is defined as the actual number of megawatt-hours generated by the coal plants divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period.

(5) The load factor is determined by dividing capacity factor by the equivalent availability factor.

(6) Midwest Generation refers to unplanned maintenance as a forced outage.

(7) The average realized energy price reflects the average price at which energy is sold into the market including the effects of hedges, real-time and day-ahead sales and PJM fees and ancillary services. It is determined by dividing (i) operating revenue less unrealized SFAS No. 133 gains (losses) and other non-energy related revenue by (ii) total generation. Revenue related to capacity sales are excluded from the calculation of average realized energy price.

(8) The average realized energy price in 2004 represented an average, weighted by generation, of energy prices earned by the merchant coal plants and energy prices earned under the power purchase agreements with Exelon Generation. Due to the structure of the power purchase agreements with Exelon Generation (with higher capacity prices and lower energy prices), the composite data in 2004 is not directly comparable to 2005 and 2006 merchant energy prices.

Earnings from the Illinois Plants decreased $88 million in 2006 compared to 2005, and increased $1.4 billion in 2005 compared to 2004. The 2006 decrease in earnings was primarily attributable to lower energy revenues resulting from lower generation, a decrease in sales of excess SO2 emission allowances in 2006, as compared to 2005, due to lower prices for SO2 allowances and higher plant overhaul costs. Partially offsetting these decreases was an increase in unrealized gains in 2006 related to hedge contracts described below.

Earnings from the Illinois Plants, excluding discrete items discussed below, increased $438 million in 2005 compared to 2004. The 2005 increase in earnings is due to the following factors:

- substantially higher energy revenues resulting from increased average realized energy prices;
- higher fuel costs in 2004 during the period the Collins Station operated (operations ceased effective September 30, 2004);
- an increase in sales of excess SO2 emission allowances in 2005, as compared to 2004, due to higher market prices;
- the absence in 2005 as compared to 2004 of a $56 million charge recorded during the fourth quarter of 2004 related to an estimate of possible future payments under a contract indemnity agreement related to asbestos claims with respect to activities at the Illinois Plants prior to their acquisition in 1999. See "Liquidity and Capital Resources Contractual Obligations, Commitments and Contingencies Commercial Commitments Guarantees and Indemnities Indemnities Provided as Part of the Acquisition of the Illinois Plants"; and
- lower plant operating lease costs due to the termination of the Collins Station lease in April 2004.

Partially offset by:

- lower capacity revenues resulting from the expiration of the power purchase agreements with Exelon Generation;

- higher plant operation costs due to higher planned maintenance;

- higher coal costs attributable to higher coal prices primarily due to price escalation under coal and transportation agreements; and

- higher interest expense primarily attributable to a full year of interest expense in 2005 versus approximately eight months of interest expense in 2004 related to debt issued in April 2004 by Midwest Generation, which owns or leases the Illinois Plants.

Discrete items affecting the loss of the Illinois Plants in 2004 include:

- $961 million loss in 2004 related to the termination of the Collins Station lease and the return of ownership of the Collins Station to EME, and the impairment of plant assets and related inventory reserves. Management concluded that the Collins Station was not economically competitive in the marketplace given generation overcapacity and ceased operations effective September 30, 2004; and

- $29 million loss recorded in 2004 related to the impairment of small peaking units in Illinois.

Included in operating revenues were unrealized gains (losses) of $30 million, $(19) million and $(4) million in 2006, 2005 and 2004, respectively. Unrealized gains (losses) are primarily due to power contracts that did not qualify for hedge accounting under SFAS No. 133 (sometimes referred to as economic hedges). These energy contracts were entered into to hedge the price risk related to projected sales of power. During 2005 and 2004, power prices increased, resulting in mark-to-market losses on economic hedges. As economic hedge contracts were settled in 2006 the previous unrealized losses resulted in unrealized gains. The 2006 unrealized gains also included $8 million of mark-to-market gains from economic hedges for periods subsequent to December 31, 2006, resulting from a decline in market prices during the fourth quarter of 2006. See "Market Risk Exposures Commodity Price Risk" for more information regarding forward market prices.

The earnings (losses) of the Illinois Plants included interest income of $115 million for the year ended December 31, 2006 and $113 million for each of the years ended December 31, 2005 and 2004 related to loans to EME. In August 2000, Midwest Generation, which owns or leases the Illinois Plants, entered into a sale-leaseback transaction of the Powerton-Joliet facilities. The proceeds from the sale of these facilities were loaned to EME, which also provided a guarantee of the related lease obligations of Midwest Generation. The Powerton-Joliet sale-leaseback is recorded as an operating lease for accounting purposes. See "Management's Overview; Critical Accounting Policies Critical Accounting Policies Off-Balance Sheet Financing" for further discussion of these leases.

Homer City

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Operating Revenues	$ 642	$ 592	$ 497
Operating Expenses			
Fuel(1)	283	288	215
Gain on sale of emission allowances(2)	(7)	(4)	
Plant operations	106	112	88
Plant operating leases	102	102	102
Depreciation and amortization	16	16	15
Administrative and general	5	6	3
Total operating expenses	505	520	423
Operating Income	137	72	74
Other Income (Expense)			
Interest and other income	20	3	4
Interest expense	(1)	(1)	(1)
Total other income	19	2	3
Income Before Taxes	$ 156	$ 74	$ 77
Statistics			
Generation (in GWh)	12,286	13,637	13,292
Equivalent availability(3)	81.9%	85.2%	85.1%
Capacity factor(4)	74.3%	82.4%	80.1%
Load factor(5)	90.7%	96.7%	94.1%
Forced outage rate(6)	13.5%	4.8%	5.3%
Average realized energy price/MWh(7)	$ 48.02	$ 45.05	$ 35.93
Capacity revenue only (in millions)	$ 16	$ 18	$ 28
Average fuel costs/MWh	$ 23.05	$ 21.08	$ 16.15

(1) The Homer City facilities purchased SO2 emission allowances from the Illinois Plants at fair market value. Purchases were $14 million in 2006, $61 million in 2005 and $26 million in 2004. These purchases are included in fuel costs.

(2) The Homer City facilities sold excess NOx emission allowances to the Illinois Plants at fair market value. Sales to the Illinois Plants were $6 million in 2006, $5 million in 2005 and none in 2004. These sales reduced operating expenses. In addition, EME recorded a $1 million intercompany profit during 2006, eliminated in 2005, on emission allowances sold by the Homer City facilities to the Illinois Plants but not used by the Illinois Plants until 2006.

(3) The equivalent availability factor is defined as the number of megawatt-hours the coal plants are available to generate electricity divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period. Equivalent availability reflects the impact of the unit's inability to achieve full load, referred to as derating, as well as outages which result in a complete unit shutdown. The coal plants are not available during periods of planned and unplanned maintenance.

(4) The capacity factor is defined as the actual number of megawatt-hours generated by the coal plants divided by the product of the capacity of the coal plants (in MW) and the number of hours in the period.

(5) The load factor is determined by dividing capacity factor by the equivalent availability factor.

(6) Homer City refers to unplanned maintenance as a forced outage.

(7) The average realized energy price reflects the average price at which energy is sold into the market including the effects of hedges, real-time and day-ahead sales and PJM fees and ancillary services. It is determined by dividing (i) operating revenue less unrealized SFAS No. 133 gains (losses) and other non-energy related revenue by (ii) total generation.

Earnings from Homer City increased $82 million in 2006 compared to 2005 and decreased $3 million in 2005 compared to 2004. The 2006 increase was primarily attributable to the timing of unrealized gains and losses related to hedge contracts discussed below, higher average realized energy prices and lower prices of SO2 emission allowances. Partially offsetting these increases were lower generation in 2006 due to an unplanned outage at Unit 3 (net of estimated insurance recoveries) and higher coal prices. Homer City is generally classified as a baseload plant, which means the amount of generation is largely based on the availability of the plant. Accordingly, the Unit 3 outage reduced the amount of generation during 2006. Included in fuel costs were $35 million, $81 million and $42 million in 2006, 2005 and 2004, respectively, related to the net cost of SO2 emission allowances. See "Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk" for more information regarding the price of SO2 allowances.

The 2005 decrease was primarily attributable to unrealized losses related to hedge contracts, mostly offset by higher energy margin including the effect of higher wholesale energy prices, higher coal prices, higher priced SO2 emission allowances and higher plant operations costs. Homer City had higher planned equipment maintenance costs in 2005 compared to 2004 and incurred costs in 2005 related to the replacement of the catalyst for the pollution control equipment.

Included in operating revenues were unrealized gains (losses) from hedge activities of $35 million, $(41) million and $(13) million in 2006, 2005 and 2004, respectively. Unrealized gains (losses) were primarily attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges under SFAS No. 133. The ineffective portion of hedge contracts at Homer City was primarily attributable to changes in the difference between energy prices at PJM West Hub (the settlement point under forward contracts) and the energy prices at the Homer City busbar (the delivery point where power generated by the Homer City facilities is delivered into the transmission system). At December 31, 2006, unrealized losses of $11 million were recognized from the ineffective portion of cash flow hedges related to 2007. See "Market Risk Exposures Commodity Price Risk" for more information regarding forward market prices.

The average realized energy price received by Homer City in 2006, 2005 and 2004 was $48.02/MWh, $45.05/MWh and $35.93/MWh, respectively, compared to the average real-time market price at the Homer City busbar for the same periods of $45.15/MWh, $54.80/MWh and $40.79/MWh, respectively. Homer City's average realized energy price varies from the average real-time market price due to: (1) hedge contracts having been entered into in prior periods, and (2) changes in the differential in market prices at the PJM West Hub versus the Homer City busbar. The increase in the differential is referred to as a widening of the basis between these PJM locations. Homer City hedges its energy price risk at PJM West Hub and retains the risk that the basis between PJM West Hub and Homer City widens. During 2005, the basis between these two locations widened substantially resulting in ineffective losses on hedge contracts. See "Market Risk Exposures Commodity Price Risk Basis Risk."

Homer City Unit 3 Outage

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed resulting in a suspension of operations at this unit. Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. Homer City has adjusted its previously planned outage schedules for Unit 3 and the other Homer City units in order to minimize to the extent practicable overall outage activities for all units through the first half of 2007. The main transformer failure resulted in claims under Homer City's property and business interruption insurance policies. At December 31, 2006, Homer City had a $17 million receivable related to these claims. Resolution of the claims is subject to a number of uncertainties, including computations of the lost profit during the outage period.

Seasonal Disclosure

Due to higher electric demand resulting from warmer weather during the summer months and cold weather during the winter months, electric revenues from the Illinois Plants and the Homer City facilities vary substantially on a seasonal basis. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall) further reducing generation and increasing major maintenance costs which are recorded as an expense when incurred. Accordingly, earnings from the Illinois Plants and the Homer City facilities are seasonal and have significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. See "Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Illinois Plants" and " Energy Price Risk Affecting Sales from the Homer City Facilities" for further discussion regarding market prices.

Energy Trading

EME seeks to generate profit by utilizing its subsidiary, EMMT, to engage in trading activities in those markets in which it is active as a result of its management of the merchant power plants of Midwest Generation and Homer City. EMMT trades power, fuel and transmission congestion primarily in the eastern power grid using products available over the counter, through exchanges and from ISOs. Earnings from energy trading activities were $130 million, $195 million and $23 million in 2006, 2005 and 2004, respectively. The 2006 decrease in earnings from energy trading activities was primarily attributable to less congestion due in part to lower wholesale energy prices driven by lower natural gas prices. Volatile market conditions in 2005, driven by increased natural gas and oil prices and warmer summer temperatures, created favorable conditions for EMMT's trading strategies in 2005 compared to 2004.

San Juan Mesa

EME's earnings from the San Juan Mesa wind project were $7 million in 2006, with no earnings recorded in 2005 and 2004 due to the acquisition of the San Juan Mesa wind project on December 27, 2005.

During the first quarter of 2006, EME completed the sale of 25% of its ownership interest in the San Juan Mesa wind project to Citi Renewable Investments I LLC, a wholly owned subsidiary of Citicorp North America, Inc. Proceeds from the sale were $43 million. EME recorded a pre-tax gain on the sale of approximately $4 million during the first quarter of 2006.

Earnings from Unconsolidated Affiliates

Big 4 Projects

EME owns partnership investments (50% ownership or less) in Kern River Cogeneration Company, Midway-Sunset Cogeneration Company, Sycamore Cogeneration Company and Watson Cogeneration Company. These projects have similar economic characteristics and have been used, collectively, to secure financing by Edison Mission Energy Funding Corp., a special purpose entity. Due to similar economic characteristics and the financing related to EME's equity investments in these projects, EME evaluates them collectively and refers to them as the Big 4 projects.

Earnings from the Big 4 projects decreased $26 million in 2006 compared to 2005, and increased $16 million in 2005 compared to 2004. The 2006 change in earnings was primarily due to lower earnings from the Kern River project during 2006, compared to 2005, resulting from the expiration of the project's long-term power purchase and steam supply agreements in August 2005. Effective June 1, 2006, the project commenced selling electricity under a five-year bilateral agreement with Southern California Edison Company (SCE). The decrease in earnings was also attributable to lower earnings from the Watson and Sycamore projects during 2006, compared to 2005, primarily due to lower energy margins resulting from lower natural gas prices.

The 2005 change in earnings was largely due to higher energy prices in 2005. The impact of the higher energy prices in 2005 was partially offset by lower earnings from the Kern River project during 2005, compared to 2004, resulting from the expiration of the project's long-term power purchase and steam supply agreements described above and an unplanned outage in December 2005.

Earnings from the Big 4 projects are net of interest expense of $5 million, $9 million and $12 million in 2006, 2005 and 2004, respectively, with respect to Edison Mission Energy Funding.

Sunrise

Earnings from the Sunrise project increased $5 million in 2006 from 2005 and $1 million in 2005 from 2004. The 2006 increase was largely due to higher capacity revenues and availability incentive payments in 2006.

March Point

Earnings from March Point decreased $8 million in 2005 from 2004. The 2005 decrease is primarily attributable to earnings recorded for a full year in 2004, compared to nine months in 2005 due to the impairment charge recorded during the third quarter of 2005 discussed below.

Impairment Loss on Equity Method Investment

During the third quarter of 2005, EME fully impaired its equity investment in the March Point project following an updated forecast of future project cash flows. The March Point project is a 140 MW natural gas-fired cogeneration facility located in Anacortes, Washington, in which a subsidiary of EME owns a 50% partnership interest. The March Point project sells electricity to Puget Sound Energy, Inc. under two power purchase agreements that expire in 2011 and sells steam to Equilon Enterprises, LLC (a subsidiary of Shell Oil) under a steam supply agreement that also expires in 2011. March Point purchases a portion of its fuel requirements under long-term contracts with the remaining requirements purchased at current market prices. March Point's power sales agreements do not provide for a price adjustment related to the project's fuel costs. During the first nine months of 2005, long-term natural gas prices increased substantially, thereby adversely affecting the future cash flows of the March Point project. As a result, management concluded that its investment was impaired and recorded a $55 million charge during the third quarter of 2005.

Doga

In accordance with Financial Accounting Standards Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46(R)), EME determined that it was not the primary beneficiary of the Doga project and, accordingly, deconsolidated this project at March 31, 2004. Beginning April 1, 2004, EME recorded its interest in the Doga project on the equity method basis of accounting. Earnings from the Doga project were $1 million in 2006, $7 million in 2005 and $1 million in 2004, representing earnings from the final three quarters of 2004.

Earnings from the Doga project decreased $6 million in 2006, compared to the corresponding period of 2005. The decrease in earnings was primarily due to a change in the Turkish corporate tax rate. In June 2006, the corporate tax rate in Turkey was reduced from 30% to 20%. Although the decrease in the corporate tax rate will reduce future income tax payments, Doga reported a loss from a reduction in deferred tax assets (related to levelization of income under the power purchase agreement for financial reporting purposes).

Seasonal Disclosure

EME's third quarter equity in income from its energy projects is materially higher than equity in income related to other quarters of the year due to warmer weather during the summer months and because a number of EME's energy projects located on the West Coast have power sales contracts that provide for higher payments during the summer months.

Corporate Interest Income

EME corporate interest income increased $27 million in 2006 from 2005 and $49 million in 2005 from 2004. The 2006 increase was primarily attributable to higher interest rates in 2006 compared to 2005. The 2005 increase was primarily attributable to higher average cash balances in 2005 compared to 2004 due largely to cash proceeds received from the sale of international operations.

Corporate Interest Expense

	Years Ended December 31,		
	2006	**2005**	**2004**
		(in millions)	
Interest expense to third parties	$ 138	$ 157	$ 170
Interest expense to Midwest Generation(1)	115	113	113
Total corporate interest expense	$ 253	$ 270	$ 283

(1) Includes interest expense of EMMT related to loans from Midwest Generation for margining.

Interest Expense to Third Parties

EME's interest expense to third parties decreased $19 million in 2006, compared to the corresponding period of 2005. The decrease was primarily attributable to lower interest rates resulting from EME's refinancing in June 2006.

Corporate Administrative and General Expenses

Administrative and general expenses decreased $13 million in 2006 from 2005, and $24 million in 2005 from 2004. The 2006 decrease was primarily due to $13 million of costs incurred during 2005 for severance and related costs in connection with EME restructuring activities. The 2005 decrease was primarily due to decreased use of third-party consultants partially offset by charges for severance and related costs recorded in 2005.

Gain on Sale of Investments

On January 4, 2004, EME completed the sale of its ownership interest in Four Star Oil & Gas Company and recorded a pre-tax gain of $47 million. Proceeds from the sale were approximately $100 million.

On March 31, 2004, EME completed the sale of 100% of its stock of Mission Energy New York, Inc., which in turn owned a 50% partnership interest in Brooklyn Navy Yard, to a third party for a sales price of approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt was $146 million in 2006 related to the early repayment of all EME's 10% senior notes due August 15, 2008 and 9.875% senior notes due April 15, 2011.

Loss on early extinguishment of debt was $4 million in 2005. Extinguishment of debt consisted of a $4 million loss related to the early repayment of EME's junior subordinated debentures recorded during the first quarter of 2005.

Other Income (Expense), Net

Other income (expense), net increased $13 million in 2006 from 2005 and $8 million in 2005 from 2004. The 2006 increase was partially attributable to an $8 million gain related to receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter of 2006.

Income Taxes

EME's income tax provision (benefit) from continuing operations was $189 million in 2006, $208 million in 2005 and $(406) million in 2004. Income tax benefits are recognized pursuant to a tax-allocation agreement with Edison International. See "Liquidity and Capital Resources EME's Liquidity as a Holding Company Intercompany Tax-Allocation Agreement." EME recognized $16 million, $8 million and $7 million of production tax credits related to wind projects for the years ended December 31, 2006, 2005 and 2004, respectively, and $14 million, $8 million and $8 million for each period related to estimated state income tax benefits allocated from Edison International. During the second quarter of 2005, EME resolved a dispute regarding additional taxes asserted by the Internal Revenue Service during the audit of the 1994-1996 tax returns. As a result of the resolution of this item, EME reversed $11.5 million of accrued taxes, recording this amount as a reduction of income taxes during the second quarter of 2005. During the second quarter of 2004, EME recorded a tax benefit of $368 million primarily relating to the loss on the termination of the Collins Station lease, and during the first quarter of 2004, EME recorded a tax provision of $18 million relating to the sale of 100% of its stock in Edison Mission Energy Oil & Gas, which in turn held interests in Four Star Oil & Gas.

Cumulative Effect of Change in Accounting Principle

Statement of Financial Accounting Standard Interpretation No. 47

Effective December 31, 2005, EME adopted Financial Accounting Standard Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). EME recorded a $1 million, after tax, decrease to net income as the cumulative effect of the adoption of FIN 47.

Annual Results of Discontinued Operations for 2006, 2005 and 2004

Income from discontinued operations, net of tax, was $98 million in 2006, $29 million in 2005 and $690 million in 2004. The 2006 increase is largely attributable to distributions received from the Lakeland project, discussed below. In addition, EME recorded a tax benefit adjustment of $22 million during the fourth quarter of 2006, which resulted from resolution of a tax uncertainty pertaining to the ownership interest in a foreign project. During 2005, EME completed the following sales:

On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) hydroelectric power project to CBK Projects B.V. Proceeds from the sale were approximately $104 million.

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project to IPM. Proceeds from the sale were approximately $20 million.

The aggregate after-tax gain on sale of the projects mentioned above was $5 million.

During the fourth quarter of 2005, EME recorded an after-tax charge of $25 million related to a tax indemnity for a project sold to IPM in December 2004. This charge related to an adverse tax court ruling in Spain, which the local company appealed. During the third quarter of 2005, EME recorded tax benefit adjustments of $28 million, which resulted from completion of the 2004 federal and California income tax returns and quarterly review of tax accruals. Most of the tax adjustments are related to the sale of the international projects in December 2004.

During 2004, EME completed the following sales:

On September 30, 2004, EME sold its 51.2% interest in Contact Energy to Origin Energy New Zealand Limited. Consideration for the sale was NZ$1,101.4 million (approximately US$739 million) in cash and NZ$535 million (approximately US$359 million) of debt assumed by the purchaser.

On December 16, 2004, EME sold the stock and related assets of MEC International B.V. (MECIBV) to IPM. The sale of MECIBV included the sale of EME's interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico. Consideration from the sale of MECIBV was $2.0 billion in cash. EME retained its ownership of the subsidiaries associated with the Lakeland project and some inactive subsidiaries.

The aggregate after-tax gain on the sale of the above-referenced international projects was $533 million.

Lakeland Project

EME previously owned a 220 MW power plant located in the United Kingdom, referred to as the Lakeland project. An administrative receiver was appointed in 2002 as a result of a default by the project's counterparty, a subsidiary of TXU Europe Group plc. Following a claim for termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims have been settled, EME has received to date payments of £13 million (approximately $24 million) in 2005, £72 million (approximately $125 million) in 2006 and £4 million (approximately $8 million) in January 2007. The after-tax income attributable to the Lakeland project was $85 million and $24 million for 2006 and 2005, respectively, and none in 2004. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounts for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

Related Party Transactions

Specified EME subsidiaries have ownership in partnerships that sell electricity generated by their project facilities to SCE and others under the terms of long-term power purchase agreements. Sales by these partnerships to SCE under these agreements amounted to $756 million, $932 million and $824 million in 2006, 2005 and 2004, respectively.

New Accounting Pronouncements

Accounting Principles Adopted

Statement of Financial Accounting Standards Interpretation No. 48

In July 2006, the FASB issued Financial Accounting Standards Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN No. 48), which clarifies the accounting for uncertain tax positions. FIN No. 48 requires an enterprise to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. EME adopted FIN No. 48 effective January 1, 2007. EME recorded a cumulative-effect adjustment that decreased retained earnings by $1 million upon adoption of FIN No. 48.

Statement of Financial Accounting Standards No. 155

In February 2006, the FASB issued Statement of Financial Accounting Standards No. 155, "Accounting for Certain Hybrid Financial Instruments" (SFAS No. 155), which amends SFAS No. 133 and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for at fair value at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated. SFAS No. 155 is effective for all financial instruments acquired, issued, or subject to remeasurement after January 1, 2007. The fair value election provided for in paragraph 4(c) of this Statement may also be applied upon adoption of this Statement for hybrid financial instruments that had been bifurcated under paragraph 12 of SFAS No. 133 prior to the adoption of this Statement. The adoption of this standard had no effect on EME's consolidated financial statements for the six months ended June 30, 2007.

Statement of Financial Accounting Standards No. 123(R)

Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment" (SFAS No. 123(R)) requires companies to use the fair value accounting method for stock-based compensation. EME implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, SFAS No. 123(R) was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. SFAS No. 123(R) resulted in the recognition of expense for all stock-based compensation awards. In addition, EME elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, "Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards." Prior to January 1, 2006, EME used the intrinsic value method of accounting, which resulted in no recognition of expense for Edison International stock options. Prior to adoption of SFAS No. 123(R), EME presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other operating liabilities" in the consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $7 million excess tax benefit is classified as a financing cash inflow in 2006.

Due to the adoption of SFAS No. 123(R), EME recorded a cumulative effect adjustment that increased net income by approximately $0.4 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

FASB Staff Position FIN 46(R)-6

In April 2006, the FASB issued Staff Position FIN 46(R)-6, "Determining Variability to be Considered in Applying FIN 46(R)." FIN 46(R)-6 states that the variability to be considered in applying FIN 46(R) shall be based on an analysis of the design of the entity following a two-step process. The first step is to analyze the nature of the risks in the entity. The second step would be to determine the purpose(s) for which the entity was created and determine the variability (created by the risks identified in Step 1) the entity is designed to create and pass along to its interest holders. The guidance in this FASB Staff Position was effective prospectively beginning July 1, 2006, although companies had until December 31, 2006 to elect retrospective applications. EME adopted FIN 46(R)-6 prospectively beginning July 1, 2006. Applying the guidance had no effect on EME's consolidated financial statements for the year ending December 31, 2006.

Statement of Financial Accounting Standards No. 158

In September 2006, the FASB issued Statement of Financial Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-Retirement Plans" (SFAS No. 158), which amends the accounting by employers for defined benefit pension plans and postretirement benefits other than pensions. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension and other postretirement plans as assets or liabilities in their balance sheet; the assets or liabilities are offset through other comprehensive income. EME adopted SFAS No. 158 prospectively on December 31, 2006. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends; EME already has a fiscal year-end measurement date for all of its postretirement plans. Upon adoption, EME recorded additional postretirement benefit liabilities of $10 million (included in other long-term liabilities) and a reduction to accumulated other comprehensive income (a component of shareholder's equity) of $6 million, net of tax.

Staff Accounting Bulletin No. 108

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB No. 108 requires additional quantitative testing to determine whether a misstatement is material. EME implemented SAB No. 108 for the filing of its Annual Report on Form 10-K for the year ended December 31, 2006. Applying the guidance had no effect on EME's consolidated financial statements for the year ended December 31, 2006.

Accounting Principles Not Yet Adopted

FASB Staff Position FIN No. 39-1

In April 2007, the FASB issued FIN No. 39-1, "Amendment of FASB Interpretation No. 39." FIN No. 39-1 amends paragraph 3 of FIN No. 39 to replace the terms conditional contracts and exchange contracts with the term derivative instruments as defined in SFAS No. 133. FIN No. 39-1 also states that under master netting arrangements if collateral is based on fair value, then it must be netted with the fair value of derivative assets/liabilities if an entity qualified and elected the option to net those amounts. EME will adopt FIN No. 39-1 on January 1, 2008. Adoption of this position will result in netting a portion of margin and cash collateral deposits with derivative liabilities on EME's consolidated balance sheets, but will have no impact on EME's consolidated statements of income (loss).

Statement of Financial Accounting Standards No. 157

In September 2006, the FASB issued Statement of Financial Standards No. 157, "Fair Value Measurements" (SFAS No. 157), which clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. EME will adopt SFAS No. 157 on January 1, 2008. EME is currently evaluating the impact of adopting SFAS No. 157 on its consolidated financial statements.

Statement of Financial Accounting Standards No. 159

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, "Fair Value Option for Financial Assets and Liabilities, Including an Amendment of FASB Statement No. 115 (SFAS No. 159)," which provides an option to report eligible financial assets and liabilities at fair value, with changes in fair value recognized in earnings. Upon adoption, the first remeasurement to fair value would be reported as a cumulative-effect adjustment to the opening balance of retained earnings. EME will adopt SFAS No. 159 on January 1, 2008. EME is currently evaluating whether it will opt to report any financial assets and liabilities at fair value and the impact, if adopted, on its consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2007, EME and its subsidiaries had cash and cash equivalents and short-term investments of $1.0 billion, EME had a total of $522 million of available borrowing capacity under its $600 million corporate credit facility, and Midwest Generation had a total of $467 million of available borrowing capacity under its $500 million working capital facility. EME's consolidated debt at June 30, 2007 was $4.0 billion. In addition, EME's subsidiaries had $4.0 billion of long-term lease obligations related to the sale-leaseback transactions that are due over periods ranging up to 28 years.

Capital Expenditures

At June 30, 2007, the three-year estimated capital expenditures by EME's subsidiaries related to existing projects, corporate activities and turbine commitments were as follows:

	July through December 2007	2008	2009
	(in millions)		
Illinois Plants			
Plant capital expenditures	$ 11	$ 45	$ 26
Environmental expenditures	25	39	66
Homer City Facilities			
Plant capital expenditures	11	26	20
Environmental expenditures	6	9	15
Wind and Thermal Projects			
Projects under construction	194		
Turbine commitments	408	534	426
Corporate capital expenditures	8	7	7
Total	$ 663	$ 660	$ 560

Expenditures for Existing Projects

Plant capital expenditures relate to non-environmental projects such as upgrades to boiler and turbine controls and dust collection/mitigation systems, a spare main power transformer, railroad interconnection and an expansion of a coal cleaning plant refuse site. Environmental expenditures relate to environmental projects such as mercury emission monitoring and control and selective catalytic reduction performance improvements at the Homer City facilities and various projects at the Illinois Plants to achieve specified emissions reductions such as installation of mercury controls. EME plans to finance these expenditures with financings, cash on hand or cash generated from operations. See further discussion regarding these and possible additional capital expenditures, including environmental control equipment at the Homer City facilities, under "Management's Overview; Critical Accounting Policies Management's Overview Business Strategy," "Liquidity and Capital Resources Environmental Matters and Regulations Air Quality Regulation Clean Air Act Illinois," and "Liquidity and Capital Resources Environmental Matters and Regulations Air Quality Regulation Mercury Regulation."

Expenditures for New Projects

EME expects to make substantial investments in new projects during the next three years. As of June 30, 2007, EME had a development pipeline of potential wind projects with an installed capacity of approximately 3,100 MW (the development pipeline represents potential projects for which EME either owns the project rights or has exclusive negotiation rights). Completion of these projects is dependent upon a number of items which may include, depending on the project's status, completion of a power sales agreement, permits, an interconnection agreement or other agreements necessary to start construction. Additional projects may from time to time be added to the development pipeline, and there is no assurance that the projects included in the development pipeline currently or added in the future will lead to the successful completion of a wind project.

EME's Historical Consolidated Cash Flow

Consolidated Cash Flows from Operating Activities

Interim Results

Cash used in operating activities from continuing operations increased $429 million in the first six months of 2007, compared to the first six months of 2006. The 2007 increase was primarily attributable to an increase of $119 million in required margin and collateral deposits in 2007 for EME's hedging and trading activities, compared to a decrease of $363 million in 2006. This change resulted from an increase in forward market prices in 2007 from 2006. The increase was also due to timing of cash receipts and disbursements related to working capital items. Partially offsetting these increases was higher pre-tax income from continuing operations in 2007 compared to 2006.

Cash provided by operating activities from discontinued operations decreased $77 million in the first six months of 2007, compared to the first six months of 2006. The 2007 decrease reflects higher distributions received in 2006 compared to 2007 from the Lakeland power project. See "Results of Operations Interim Results of Discontinued Operations Lakeland Project" for more information regarding these distributions.

Annual Results

Net cash provided by (used in) operating activities:

	Years Ended December 31,		
	2006	**2005**	**2004**
	(in millions)		
Continuing operations	$ 1,131	$ (239)	$ (353)
Discontinued operations	94	20	(434)
	$ 1,225	$ (219)	$ (787)

The 2006 increase in cash provided by operating activities from continuing operations was primarily attributable to a decrease of $625 million in required margin and collateral deposits in 2006 for EME's hedging and trading activities, compared to an increase of $656 million in 2005. This change resulted from a decrease in forward market prices in 2006 from 2005 and settlement of hedge contracts during 2006.

The 2005 decrease in cash used in operating activities from continuing operations was primarily attributable to the $960 million lease termination payment in 2004 related to the Collins Station lease and improved operating income in 2005. Partially offsetting these decreases was $656 million in required margin and collateral deposits in 2005 for EME's hedging and trading activities, compared to $30 million in 2004. This increase in margin and collateral deposits resulted from an increase in forward market prices.

Cash provided by operating activities from discontinued operations increased in 2006 from 2005 reflecting higher distributions received in 2006 compared to 2005 from the Lakeland power project. See "Results of Operations Annual Results of Discontinued Operations for 2006, 2005 and 2004 Lakeland Project" for more information regarding these distributions. Cash used in operating activities from discontinued operations in 2004 primarily reflects settlement of working capital items from the sale of EME's international operations.

Consolidated Cash Flows from Financing Activities

Interim Results

Cash used in financing activities from continuing operations increased $169 million in the first six months of 2007, compared to the first six months of 2006. The 2007 increase was primarily attributable to dividend payments made to MEHC of $925 million in 2007 compared to $12 million in 2006. In May 2007, net proceeds of $2.7 billion were received from EME's issuance of senior notes, which were mostly used to repay $587 million of EME's outstanding senior notes, $999.8 million of Midwest Generation's second priority senior secured notes, $327.8 million of Midwest Generation's senior secured term loan facility. In June 2006, net proceeds of $1 billion were received from EME's issuance of senior notes, which were mostly used to repay $965 million of EME's outstanding senior notes. Tender premiums and related fees paid associated with the foregoing financings were $137 million and $136 million in 2007 and 2006, respectively.

Annual Results

Net cash used in financing activities:

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Continuing operations	$ (461)	$ (773)	$ (21)
Discontinued operations			(144)
	$ (461)	$ (773)	$ (165)

The 2006 decrease in cash used in financing activities from continuing operations was primarily attributable to net proceeds of $1 billion received from EME's issuance of senior notes in 2006, which were mostly used to repay $1 billion of EME's outstanding senior notes and $139 million paid for tender premiums and related fees. In addition, dividend payments were made to MEHC of $360 million in 2005 compared to $51 million in 2006. In 2006, Midwest Generation also had net repayments of $170 million under its credit facility.

The 2005 increase in cash used in financing activities from continuing operations was primarily attributable to dividend payments made to MEHC of $360 million during 2005, compared to $74 million during 2004. The increase was also due to the repayment of EME's junior subordinated debentures of $150 million in January 2005 and a $302 million repayment in April 2005 related to Midwest Generation's existing term loan.

Cash used in financing activities from discontinued operations in 2004 primarily reflects repayment of debt and dividends to minority shareholders.

Consolidated Cash Flows from Investing Activities

Interim Results

Cash used in investing activities from continuing operations increased $70 million in the first six months of 2007, compared to the first six months of 2006. The 2007 increase was primarily due to higher capital expenditures and turbine deposits in 2007, compared to 2006, largely related to the wind projects. Mostly offsetting these increases was net maturities and sales of marketable securities of

$240 million in the first six months of 2007, compared to net purchases of marketable securities of $76 million in the first six months of 2006. In addition, EME received proceeds of $43 million from the sale of 25% of its ownership interest in the San Juan Mesa project during the first quarter of 2006. EME also paid $11 million and $18 million towards the purchase price of the Wildorado wind project during the second quarter of 2007 and first quarter of 2006, respectively.

Annual Results

Net cash provided by (used in) investing activities:

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Continuing operations	$ (706)	$ (134)	$ 2,707
Discontinued operations		5	18
	$ (706)	$ (129)	$ 2,725

The 2006 increase in cash used in investing activities from continuing operations was primarily due to net purchases of marketable securities of $375 million in 2006, compared to $43 million in 2005. In addition, EME paid $18 million towards the purchase price of the Wildorado wind project during 2006, incurred higher capital expenditures in 2006 and received lower proceeds from sales of projects.

The 2005 increase in cash used in investing activities from continuing operations was primarily attributable to proceeds of $2.7 billion received in 2004 from the sale of most of EME's international operations and $154 million paid towards the purchase price for the San Juan Mesa project in December 2005. Proceeds of $124 million received in 2005 from the sale of EME's 25% investment in the Tri Energy project and EME's 50% investment in the CBK project were comparable to proceeds of $118 million received in 2004. Partially offsetting the 2005 increase were net purchases of marketable securities of $43 million in 2005, compared to $120 million in 2004.

Credit Ratings

Overview

Credit ratings for EME, Midwest Generation and EMMT, at June 30, 2007, were as follows:

	Moody's Rating	S&P Rating	Fitch Rating
EME	B1	BB-	BB-
Midwest Generation	Baa3	BB+	BBB-
EMMT	Not Rated	BB-	Not Rated

EME cannot provide assurance that its current credit ratings or the credit ratings of its subsidiaries will remain in effect for any given period of time or that one or more of these ratings will not be lowered. EME notes that these credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

EME does not have any "rating triggers" contained in subsidiary financings that would result in it being required to make equity contributions or provide additional financial support to its subsidiaries.

Credit Rating of EMMT

The Homer City sale-leaseback documents restrict EME Homer City's ability to enter into trading activities, as defined in the documents, with EMMT to sell forward the output of the Homer City facilities if EMMT does not have an investment grade credit rating from Standard & Poor's Ratings Services (S&P) or Moody's Investors Service, Inc. (Moody's) or, in the absence of those ratings, if it is not rated as investment grade pursuant to EME's internal credit scoring procedures. These documents include a requirement that the counterparty to such transactions, and EME Homer City, if acting as seller to an unaffiliated third party, be investment grade. EME currently sells all the output from the Homer City facilities through EMMT, which has a below investment grade credit rating, and EME Homer City is not rated. Therefore, in order for EME to continue to sell forward the output of the Homer City facilities, either: (1) EME must obtain consent from the sale-leaseback owner participant to permit EME Homer City to sell directly into the market or through EMMT; or (2) EMMT must provide assurances of performance consistent with the requirements of the sale-leaseback documents. EME has obtained a consent from the sale-leaseback owner participant that will allow EME Homer City to enter into such sales, under specified conditions, through December 31, 2008. EME Homer City continues to be in compliance with the terms of the consent. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Homer City Facilities."

Margin, Collateral Deposits and Other Credit Support for Energy Contracts

In connection with entering into contracts in support of EME's hedging and energy trading activities (including forward contracts, transmission contracts and futures contracts), EME's subsidiary, EMMT, has entered into agreements to mitigate the risk of nonperformance. EME has entered into guarantees in support of EMMT's hedging and trading activities; however, because the credit ratings of EMMT and EME are below investment grade, EME has historically also provided collateral in the form of cash and letters of credit for the benefit of counterparties related to accounts payable and unrealized losses in connection with these hedging and trading activities. At June 30, 2007, EMMT had deposited $93 million in cash with brokers in margin accounts in support of futures contracts and had deposited $99 million with counterparties in support of forward energy and transmission contracts. In addition, EME had issued letters of credit of $32 million in support of commodity contracts at June 30, 2007.

Future cash collateral requirements may be higher than the margin and collateral requirements at June 30, 2007, if wholesale energy prices increase or the amount hedged increases. EME estimates that margin and collateral requirements for energy contracts outstanding as of June 30, 2007 could increase by approximately $260 million over the remaining life of the contracts using a 95% confidence level.

Midwest Generation has cash on hand and a $500 million working capital facility to support margin requirements specifically related to contracts entered into by EMMT related to the Illinois Plants. At June 30, 2007, Midwest Generation had available $467 million of borrowing capacity under this credit facility. As of June 30, 2007, Midwest Generation had $68 million in loans receivable from EMMT for margin advances. In addition, EME has cash on hand and $522 million of borrowing capacity available under a $600 million working capital facility to provide credit support to subsidiaries. See " EME's Liquidity as a Holding Company" for further discussion.

EME's Liquidity as a Holding Company

Overview

At June 30, 2007, EME had corporate cash and cash equivalents and short-term investments of $745 million to meet liquidity needs. Cash distributions from EME's subsidiaries and partnership investments and unused capacity under its corporate credit facility represent EME's major sources of liquidity to meet its cash requirements. The timing and amount of distributions from EME's subsidiaries may be affected by many factors beyond its control. See " Dividend Restrictions in Major Financings."

Intercompany Tax-Allocation Agreement

EME is included in the consolidated federal and combined state income tax returns of Edison International and is eligible to participate in tax-allocation payments with other subsidiaries of Edison International in circumstances where domestic tax losses are incurred. The right of EME to receive and the amount of and timing of tax-allocation payments are dependent on the inclusion of EME in the consolidated income tax returns of Edison International and its subsidiaries and other factors, including the consolidated taxable income of Edison International and its subsidiaries, the amount of net operating losses and other tax items of EME, its subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. EME receives tax-allocation payments for tax losses when and to the extent that the consolidated Edison International group generates sufficient taxable income in order to be able to utilize EME's consolidated tax losses in the consolidated income tax returns for Edison International and its subsidiaries. Based on the application of the factors cited above, EME is obligated during periods it generates taxable income to make payments under the tax-allocation agreements. EME made tax-allocation payments to Edison International of $156 million and $162 million during the first six months of 2007 and 2006, respectively. EME made net tax-allocation payments to Edison International of $151 million and $129 million in 2006 and 2005, respectively.

Dividend Restrictions in Major Financings

General

Each of EME's direct or indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Assets of EME's subsidiaries are not available to satisfy EME's obligations or the obligations of any of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law and the terms of financing arrangements of the parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or to its subsidiary holding companies.

Key Ratios of EME's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME's principal subsidiaries required by financing arrangements at June 30, 2007 or for the twelve months ended June 30, 2007:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Illinois Plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.24 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.64 to 1

Midwest Generation Financing Restrictions on Distributions

Midwest Generation is bound by the covenants in its credit agreement and certain covenants under the Powerton-Joliet lease documents with respect to Midwest Generation making payments under the leases. These covenants include restrictions on the ability to, among other things, incur debt, create liens on its property, merge or consolidate, sell assets, make investments, engage in transactions with affiliates, make distributions, make capital expenditures, enter into agreements restricting its ability to make distributions, engage in other lines of business or engage in transactions for any speculative purpose. In order for Midwest Generation to make a distribution, it must be in compliance with the covenants specified under its credit agreement, including maintaining a debt to capitalization ratio of no greater than 0.60 to 1.

EME Homer City (Homer City Facilities)

EME Homer City completed a sale-leaseback of the Homer City facilities in December 2001. In order to make a distribution, EME Homer City must be in compliance with the covenants specified in the lease agreements, including the following financial performance requirements measured on the date of distribution:

> At the end of each quarter, the senior rent service coverage ratio for the prior twelve-month period (taken as a whole) must be greater than 1.7 to 1. The senior rent service coverage ratio is defined as all income and receipts of EME Homer City less amounts paid for operating expenses, required capital expenditures, taxes and financing fees divided by the aggregate amount of the debt portion of the rent, plus fees, expenses and indemnities due and payable with respect to the lessor's debt service reserve letter of credit.

At the end of each quarter, the equity and debt portions of rent then due and payable must have been paid. The senior rent service coverage ratio (discussed above) projected for each of the prospective two twelve-month periods must be greater than 1.7 to 1. No more than two rent default events may have occurred, whether or not cured. A rent default event is defined as the failure to pay the equity portion of the rent within five business days of when it is due.

EME Corporate Credit Facility Restrictions on Distributions from Subsidiaries

EME's corporate credit facility contains covenants that restrict its ability, and the ability of several of its subsidiaries, to make distributions. This restriction binds the subsidiaries through which EME owns the Westside projects, the Sunrise project, the Illinois Plants, the Homer City facilities and the Big 4 projects. These subsidiaries would not be able to make a distribution to EME if an event of default were to occur and be continuing under EME's corporate credit facility after giving effect to the distribution.

In addition, EME granted a security interest in an account into which all distributions received by it from the Big 4 projects are deposited. EME is free to use these distributions unless and until an event of default occurs under its corporate credit facility.

As of June 30, 2007, EME had no borrowings and $78 million of letters of credit outstanding under this credit facility.

Contractual Obligations, Commitments and Contingencies

Contractual Obligations

Interim Update at June 30, 2007

Long-term Debt

EME's long-term principal debt maturities plus interest payments as of June 30, 2007 were $247 million for the remainder of 2007, $299 million in 2008, $305 million in 2009, $290 million in 2010, $291 million in 2011, and $5.7 billion thereafter. These amounts have been updated primarily to reflect EME's financing activities completed during the second quarter of 2007. See "Management's Overview; Critical Accounting Policies Management's Overview Refinancing Senior Notes Offering" for additional details.

Capital Improvements

At June 30, 2007, EME's subsidiaries had firm commitments to spend approximately $229 million during the remainder of 2007 and $24 million in 2008 on capital and construction expenditures. The majority of these expenditures relate to the construction of wind projects. Also included are expenditures for dust collection and mitigation systems and environmental improvements. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

Turbine Commitments

At June 30, 2007, EME had entered into agreements with vendors securing 669 wind turbines (1,414 MW) with remaining commitments of $382 million in 2007, $534 million in 2008, and $426 million in 2009.

In addition, EME had entered into an agreement to purchase five gas turbines and related equipment for an aggregate purchase price of approximately $145 million. In June 2007, EME entered into a change order agreement with the seller of the turbines reducing the number of gas turbines to four with a remaining commitment of $26 million at June 30, 2007. In addition, EME recorded $21 million included in prepaid expenses and other in its consolidated balance sheet with respect to a refund of the turbine payments. Subsequent to June 30, 2007, EME entered into additional change order agreements for the remaining four gas turbines. EME expects to receive refunds totaling $112 million during the third quarter of 2007 with respect to the five turbines.

Fuel Supply Contracts

Midwest Generation and EME Homer City have entered into additional fuel purchase commitments during the first six months of 2007. These additional commitments are currently estimated to be $6 million for the remainder of 2007, $208 million in 2008, $153 million in 2009, and $77 million in 2010.

Coal Transportation Agreements

Midwest Generation has contractual agreements for the transport of coal to its facilities. The primary contract is with Union Pacific Railroad (and various delivering carriers) which extends through 2011. Midwest Generation's commitments under this contract are based on actual coal purchases from the Powder River Basin (PRB). Accordingly, contractual obligations for transportation are based on coal volumes set forth in fuel supply contracts. The increase in transportation commitments entered into during the first six months of 2007 relates to additional volumes of fuel purchases using the terms of existing transportation agreements. These commitments are currently estimated to be $8 million for the remainder of 2007, $110 million for 2008, $75 million for 2009, and $77 million for 2010.

Contractual Obligations at December 31, 2006

The following table summarizes EME's significant consolidated contractual obligations as of December 31, 2006.

		Payments Due by Period (in millions)			
Contractual Obligations	**Total**	**Less than 1 year**	**1 to 3 years**	**3 to 5 years**	**More than 5 years**
Long-term debt(1)	$ 4,692	$ 375	$ 1,089	$ 716	$ 2,512
Operating lease obligations	4,407	360	713	664	2,670
Purchase obligations:					
Capital improvements	186	186			
Turbine commitments	489	463	26		
Fuel supply contracts	685	365	239	71	10
Gas transportation agreements	92	8	16	16	52
Coal transportation	455	220	159	76	
Other contractual obligations	43	11	22	10	
Employee benefit plan contribution(2)	15	15			
Total Contractual Obligations	$ 11,064	$ 2,003	$ 2,264	$ 1,553	$ 5,244

(1) See "Audited Consolidated Financial Statements of Edison Mission Energy Notes to Consolidated Financial Statements Note 8. Financial Instruments" for additional details. Table assumes long-term debt is held to maturity, except the Midwest Generation senior secured notes which are assumed to be held until 2014. Amount also includes interest payments over applicable period of the debt.

(2) Amount includes estimated contribution for pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2007 are not available. For more information, see "Audited Consolidated Financial Statements of Edison Mission Energy Notes to Consolidated Financial Statements Note 11. Compensation and Benefit Plans Pension Plans and Postretirement Benefits Other Than Pensions."

Operating Lease Obligations

At December 31, 2006, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet Stations and the Homer City facilities. During 2000, EME entered into sale-leaseback transactions for two power facilities, the Powerton and Joliet coal-fired stations located in Illinois, with third-party lessors. During the fourth quarter of 2001, EME entered into a sale-leaseback transaction for the Homer City coal-fired facilities located in Pennsylvania, with third-party lessors. Total minimum lease payments during the next five years are $336 million in 2007, $337 million in 2008, $336 million in 2009, $325 million in 2010, $312 million in 2011, and the minimum lease payments due after 2011 are $2.6 billion. For further discussion, see " Off-Balance Sheet Transactions Sale-Leaseback Transactions."

Purchase Obligations

Capital Improvements

At December 31, 2006, EME's subsidiaries had firm commitments for capital and construction expenditures. The majority of these expenditures relate to the construction of the 161 MW Wildorado wind project and four other wind projects totaling 181 MW. Also included are expenditures for dust collection and mitigation system and various other smaller projects. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

Turbine Commitments

At December 31, 2006, EME had entered into agreements with vendors securing 255 wind turbines (487 MW) with remaining commitments of $387 million in 2007 and $23 million in 2008. In addition, EME had entered into an agreement for the purchase of five gas turbines and related equipment for an aggregate purchase price of approximately $140 million with remaining commitments of $76 million in 2007 and $3 million in 2008.

Fuel Supply Contracts

At December 31, 2006, Midwest Generation and EME Homer City had contractual commitments to purchase coal with various third-party suppliers. The remaining contracts' lengths range from less than one year to six years. The minimum commitments are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. For further discussion, see "Market Risk Exposures Commodity Price Risk Coal Price Risk."

Gas Transportation Agreements

At December 31, 2006, EME had a contractual commitment to transport natural gas. EME is committed to pay its share of fixed monthly capacity charges under its gas transportation agreement, which has a remaining contract length of 11 years.

Coal Transportation Agreements

At December 31, 2006, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities, with remaining contract lengths that range from one year to five years. Midwest Generation's primary contract is with Union Pacific Railroad (and various delivering carriers) which extends through 2011. Midwest Generation commitments under this agreement are based on actual coal purchases from the PRB. Accordingly, Midwest Generation's contractual obligations for transportation are based on coal volumes set forth in their fuel supply contracts. EME Homer City commitments under its agreements are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. Although trucking remains the predominant mode of transportation for coal shipments to the Homer City facilities, rail transportation is expected to increase in 2007 as EME Homer City diversifies its alternative modes of transporting coal to the plant site.

Commercial Commitments

Standby Letters of Credit

At June 30, 2007, standby letters of credit aggregated $83 million and were scheduled to expire as follows: $16 million in 2007 and $67 million in 2008.

Guarantees and Indemnities

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Powerton and Joliet Stations in Illinois, the Collins Station in Illinois, and the Homer City facilities in Pennsylvania, EME and several of its subsidiaries entered into tax indemnity agreements. Under these tax indemnity agreements, these entities agreed to indemnify the lessors in the sale-leaseback transactions for specified adverse tax consequences that could result in certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these potential obligations, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities. In connection with the termination of the Collins Station lease in April 2004, Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor.

Indemnities Provided as Part of the Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois Plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison takes all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Asset Sale Agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were approximately 179 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at June 30, 2007. Midwest Generation had recorded a $64 million liability at June 30, 2007 related to this matter.

The amounts recorded by Midwest Generation for the asbestos-related liability are based upon a number of assumptions. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos litigation in the United States, could cause the actual costs to be higher or lower than projected.

Indemnity Provided as Part of the Acquisition of the Homer City Facilities

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale. Payments would be triggered under this indemnity by a claim from the sellers. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. EME has not recorded a liability related to this indemnity.

Indemnities Provided under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At June 30, 2007, EME had recorded a liability of $94 million related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. EME has not recorded a liability related to these indemnities.

Capacity Indemnification Agreements

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power sales agreements. In addition, a subsidiary of EME has guaranteed the obligations of Sycamore Cogeneration Company under its project power sales agreement to repay capacity payments to the project's power purchaser in the event that the project unilaterally terminates its performance or reduces its electric power producing capability during the term of the power sales agreement. The obligations under the indemnification agreements as of June 30, 2007, if payment were required, would be $89 million. EME has not recorded a liability related to these indemnities.

Contingencies

FERC Notice Regarding Investigatory Proceeding against EMMT

At the end of October 2006, EMMT was advised by the enforcement staff at the FERC that it is prepared to recommend that the FERC initiate a formal investigatory proceeding and seek monetary sanctions against EMMT for alleged violation of the Energy Policy Act of 2005 and the FERC's rules regarding market behavior, all with respect to certain bidding practices previously employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Should a formal proceeding be commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with all applicable laws and regulations and intends to contest vigorously any allegation of violation. EME cannot predict at this time the outcome of this matter or estimate the possible liability should the outcome be adverse.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in Midway-Sunset Cogeneration Company, which owns a 225 MW cogeneration facility near Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC involving claims for refunds from entities that sold power and related services into the California markets operated by the California Power Exchange and the California Independent System Operator (collectively the California Markets) at prices that were allegedly not just and reasonable, as required by the Federal Power Act.

Midway-Sunset is a party to these proceedings because Midway-Sunset was a seller in the California Markets during 2000 and 2001, both for its own account and on behalf of SCE and PG&E, the utilities to which the majority of Midway-Sunset's power was contracted for sale. As a seller into the California Markets, Midway-Sunset is potentially liable for refunds to purchasers in these markets.

The claims asserted against Midway-Sunset for refunds related to power sold into the California Markets, including power sold on behalf of SCE and PG&E, are estimated to be less than $70 million for all periods under consideration. Midway-Sunset has calculated its potential liability for refunds related to power sold into the California Markets on its own behalf (excluding power sold on behalf of SCE and PG&E) to be approximately $0.5 million for the period October 2, 2000 through June 20, 2001. Midway Sunset's potential liability for sales on its own behalf during the period May 1, 2000 through October 1, 2000 has not yet been calculated but is not expected to be material. These calculations were made in accordance with the methodology approved by the FERC, but it is possible that this methodology will be challenged.

Because Midway-Sunset did not retain any proceeds from power sold into the California Markets on behalf of SCE and PG&E in excess of the amounts to which it was entitled under the pre-existing power sales contracts, but instead passed those proceeds on to the utilities, EME believes that PG&E and SCE are obligated to reimburse Midway-Sunset for any refund liability that it incurs as a result of sales made into the California Markets on their behalf. Midway-Sunset intends vigorously to assert these positions. However, at this time EME cannot predict the outcome of this matter.

Challenges of Illinois Power Procurement Auction Results

EMMT participated successfully in the first Illinois power procurement auction, held in September 2006 according to rules approved by the Illinois Commerce Commission, and entered into two load requirements services contracts through which it is delivering electricity, capacity and specified ancillary, transmission and load following services necessary to serve a portion of Commonwealth Edison's residential and small commercial customer load, using contracted supply from Midwest Generation.

EME believes that EMMT's actions in regard to the Illinois auction were appropriate and lawful and intends to defend vigorously all of the matters described below. However, at this time EME cannot predict the outcome of these matters.

FERC Complaint

On March 16, 2007, the Office of the Attorney General for the State of Illinois filed a complaint at the FERC alleging that the prices resulting from the Illinois auction resulted in unjust and unreasonable rates under the Federal Power Act and that participating wholesale sellers in the Illinois auction had colluded and manipulated the results of the auction. All successful participants in the Illinois auction, including EMMT, were named as respondents. The Office of the Attorney General asked the FERC to order refunds and to revoke the respondents' market-based rate pricing authority. On July 24, 2007, Midwest Generation and EMMT, along with other power generation companies and utilities, entered into a settlement with the Illinois Attorney General. Enacting legislation for the settlement was signed on August 28, 2007. See " Management's Overview; Critical Accounting Policies Management's Overview Illinois Settlement" for further discussion.

Class Action Lawsuits

On April 4, 2007, EMMT was served with a complaint filed in the Circuit Court of Cook County, Illinois, by Saul R. Wexler, individually and on behalf of an alleged class of similarly situated electric ratepayers in Illinois, against Commonwealth Edison, Ameren, and all of the successful participants in the Illinois auction, including EMMT. The lawsuit alleges that the defendants, including EMMT, colluded and conspired to manipulate the auction results by price-fixing. The lawsuit seeks unspecified damages. On April 26, 2007, the defendants transferred the complaint to the U.S. District Court for the Northern District of Illinois, Eastern Division. On June 4, 2007, the defendants filed a motion to dismiss the case, which remains pending.

On March 30, 2007, David Schafer, Tim Perry, Pat Martin and Michael Murray, individually and on behalf of an alleged class of similarly situated electric ratepayers in Illinois, filed a complaint in the Circuit Court of Cook County, Illinois, against Commonwealth Edison, Ameren, and all of the successful participants in the Illinois auction, including EMMT. EMMT has not been formally served in the case. The lawsuit alleges that the defendants, including EMMT, colluded and conspired to manipulate the auction results by price-fixing. The lawsuit seeks unspecified damages. On April 26, 2007, the defendants transferred the complaint to the U.S. District Court for the Northern District of Illinois, Eastern Division. On June 4, 2007, the defendants filed a motion to dismiss the case, which remains pending.

Midwest Generation Potential Environmental Proceeding

On July 31, 2007, the US EPA issued a NOV to Midwest Generation and Commonwealth Edison. In the NOV, the US EPA alleges that, beginning in the early 1990's and into 2003, Midwest Generation or Commonwealth Edison performed construction projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration requirements and of the New Source Performance Standards of the Clean Air Act, including alleged requirements to obtain a construction permit and to install Best Available Control Technology at the time of the projects. The US EPA also alleges that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the Clean Air Act. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. Midwest Generation intends to meet with the US EPA to discuss the alleged violations. Midwest Generation is investigating the claims made by the US EPA in the NOV and potential responses and cannot predict at this time what effect this matter may have on its facilities, its results of operations or financial position.

Insurance

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed, resulting in a suspension of operations at this unit. EME Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. The main transformer failure resulted in claims under EME Homer City's property and business interruption insurance policies. At June 30, 2007, EME Homer City had a $13 million receivable, of which $11 million relates to business interruption insurance coverage and has been reflected in other income (expense), net in EME's consolidated income statements.

Tax Matters

EME and its subsidiaries remain subject to examination by the Internal Revenue Service, the California Franchise Tax Board, and other state authorities from 1994 to present. EME continues its efforts to resolve open tax issues with the Internal Revenue Service and state authorities. The timing for resolving these open tax positions is subject to uncertainty, but it is reasonably possible that some portion of these open tax positions could be resolved in the next twelve months.

Litigation

EME experiences other routine litigation in the normal course of its business. None of such pending routine litigation is expected to have a material adverse effect on EME's consolidated financial position or results of operations.

Off-Balance Sheet Transactions

Introduction

EME has off-balance sheet transactions in two principal areas: investments in projects accounted for under the equity method and operating leases resulting from sale-leaseback transactions.

Investments Accounted for under the Equity Method

EME has a number of investments in power projects that are accounted for under the equity method. Under the equity method, the project assets and related liabilities are not consolidated in EME's consolidated balance sheet. Rather, EME's financial statements reflect its investment in each entity and it records only its proportionate ownership share of net income or loss. These investments are of three principal categories.

Historically, EME has invested in qualifying facilities, those which produce electrical energy and steam, or other forms of energy, and which meet the requirements set forth in the Public Utility Regulatory Policies Act of 1978, as amended (PURPA). See "Business Regulatory Matters U.S. Federal Energy Regulation." Prior to the passage of the EPAct 2005, these regulations limited EME's ownership interest in qualifying facilities to no more than 50% due to EME's affiliation with SCE, a public utility. For this reason, EME owns a number of domestic energy projects through partnerships in which it has a 50% or less ownership interest.

Entities formed to own these projects are generally structured with a management committee or board of directors in which EME exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. EME's energy projects have generally secured long-term debt to finance the assets constructed and/or acquired by them. These financings generally are secured by a pledge of the assets of the project entity, but do not provide for any recourse to EME. Accordingly, a default on a long-term financing of a project could result in foreclosure on the assets of the project entity resulting in a loss of some or all of EME's project investment, but would generally not require EME to contribute additional capital. At December 31, 2006, entities which EME has accounted for under the equity method had indebtedness of $524 million, of which $252 million is proportionate to EME's ownership interest in these projects.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Powerton and Joliet Stations in Illinois and the Homer City facilities in Pennsylvania. See "Contractual Obligations, Commitments and Contingencies Contractual Obligations Contractual Obligations at December 31, 2006 Operating Lease Obligations." Each of these transactions was completed and accounted for in accordance with SFAS No. 98, which requires, among other things, that all the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. In each of these transactions, the assets were sold to and then leased from owner/lessors owned by independent equity investors. In addition to the equity invested in them, these owner/lessors incurred or assumed long-term debt, referred to as lessor debt, to finance the purchase of the assets. The lessor debt takes the form generally referred to as secured lease obligation bonds.

EME's subsidiaries account for these leases as financings in their separate financial statements due to specific guarantees provided by EME or another one of its subsidiaries as part of the sale-leaseback transactions. These guarantees do not preclude EME from recording these transactions as operating leases in its consolidated financial statements, but constitute continuing involvement under SFAS No. 98 that precludes EME's subsidiaries from utilizing this accounting treatment in their separate subsidiary financial statements. Instead, each subsidiary continues to record the power plants as assets in a similar manner to a capital lease and records the obligations under the leases as lease financings. EME's subsidiaries, therefore, record depreciation expense from the power plants and interest expense from the lease financing in lieu of an operating lease expense which EME uses in preparing its consolidated financial statements. The treatment of these leases as an operating lease in its consolidated financial statements in lieu of a lease financing, which is recorded by EME's subsidiaries, resulted in an increase in consolidated net income by $61 million, $72 million and $73 million in 2006, 2005 and 2004, respectively.

The lessor equity and lessor debt associated with the sale-leaseback transactions for the Powerton, Joliet and Homer City assets are summarized in the following table:

Power Station(s)	Acquisition Price	Equity Investor	Original Equity Investment in Owner/Lessor	Amount of Lessor Debt at December 31, 2006	Maturity Date of Lessor Debt
			(in millions)		
Powerton/Joliet	$ 1,367	PSEG/Citigroup, Inc.	$ 238	$330.8 Series A 679.1 Series B	2009 2016
Homer City	1,591	GECC/Metropolitan Life Insurance Company(1)	798	$276.0 Series A 521.2 Series B	2019 2026

PSEG PSEG Resources, Inc.
GECC General Electric Capital Corporation

(1) On September 29, 2005, GECC sold 10% of its investment to Metropolitan Life Insurance Company.

The operating lease payments to be made by each of EME's subsidiary lessees are structured to service the lessor debt and provide a return to the owner/lessor's equity investors. Neither the value of the leased assets nor the lessor debt is reflected in EME's consolidated balance sheet. In accordance with GAAP, EME records rent expense on a levelized basis over the terms of the respective leases. To the extent that EME's cash rent payments exceed the amount levelized over the term of each lease, EME records prepaid rent. At June 30, 2007, December 31, 2006 and 2005, prepaid rent on these leases was $668 million, $556 million and $395 million, respectively. To the extent that EME's cash rent payments are less than the amount levelized, EME reduces the amount of prepaid rent.

In the event of a default under the leases, each lessor can exercise all its rights under the applicable lease, including repossessing the power plant and seeking monetary damages. Each lease sets forth a termination value payable upon termination for default and in certain other circumstances, which generally declines over time and in the case of default may be reduced by the proceeds arising from the sale of the repossessed power plant. A default under the terms of the Powerton and Joliet or Homer City leases could result in a loss of EME's ability to use such power plant and would trigger obligations under EME's guarantee of the Powerton and Joliet leases. These events could have a material adverse effect on EME's results of operations and financial position.

EME's minimum lease obligations under its power related leases are set forth under " Contractual Obligations, Commitments and Contingencies Contractual Obligations Contractual Obligations at December 31, 2006 Operating Lease Obligations."

EME's Obligations to Midwest Generation

The proceeds, in the aggregate amount of approximately $1.4 billion, received by Midwest Generation from the sale of the Powerton and Joliet plants, described above under " Sale-Leaseback Transactions," were loaned to EME. EME used the proceeds from this loan to repay corporate indebtedness. Although interest and principal payments made by EME to Midwest Generation under this intercompany loan assist in the payment of the lease rental payments owing by Midwest Generation, the intercompany obligation does not appear on EME's consolidated balance sheet. This obligation was disclosed to the credit rating agencies at the time of the transaction and has been included by them in assessing EME's credit ratings. The following table summarizes principal payments due under this intercompany loan:

Years Ending December 31,	Principal Amount	Interest Amount	Total
		(in millions)	
2007	$ 3	$ 113	$ 116
2008	4	112	116
2009	5	112	117
2010	4	112	116
2011	9	111	120
Thereafter	1,334	401	1,735
Total	$ 1,359	$ 961	$ 2,320

EME funds the interest and principal payments due under this intercompany loan from distributions from EME's subsidiaries, including Midwest Generation, cash on hand, and amounts available under corporate lines of credit. A default by EME in the payment of this intercompany loan could result in a shortfall of cash available for Midwest Generation to meet its lease and debt obligations. A default by Midwest Generation in meeting its obligations could in turn have a material adverse effect on EME.

Environmental Matters and Regulations

Introduction

The construction and operation of power plants are subject to environmental regulation by federal, state and local authorities. EME believes that it is in substantial compliance with existing environmental regulatory requirements. Typically, environmental laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals prior to construction, operation or modification of a project or generating facility. Meeting all the necessary requirements can delay or sometimes prevent the completion of a proposed project, as well as require extensive modifications to existing projects, which may involve significant capital expenditures. If EME fails to comply with applicable environmental laws, it may be subject to injunctive relief or penalties and fines imposed by regulatory authorities.

Air Quality Regulation

Federal environmental regulations require reductions in emissions beginning in 2009 and require states to adopt implementation plans that are equal to or more stringent than the federal requirements. Compliance with these regulations and state implementation plans (SIPs) will affect the costs and the manner in which EME conducts its business, and will require EME to make substantial additional capital expenditures. There is no assurance that EME would be able to recover these increased costs from its customers or that EME's financial position and results of operations would not be materially adversely affected as a result.

Clean Air Act

On May 12, 2005, the Clean Air Interstate Rule (CAIR) was published in the Federal Register. The CAIR requires 28 eastern states and the District of Columbia to address ozone attainment issues by reducing regional NOx and SO2 emissions. The CAIR reduces the current Clean Air Act Title IV Phase II SO2 emissions allowance cap for 2010 and 2015 by 50% and 65%, respectively. The CAIR also requires reductions in regional NOx emissions in 2009 and 2015 by 53% and 61%, respectively, from 2003 levels. The CAIR has been challenged in court, which may result in changes to the substance of the rule and to the timetables for implementation.

EME expects that compliance with the CAIR and the regulations and revised SIPs developed as a consequence of the CAIR will result in increased capital expenditures and operating expenses. EME's approach to meeting these obligations will consist of a blending of capital expenditure and emission allowance purchases that will be based on an ongoing assessment of the dynamics of its market conditions.

Illinois

On December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NOx and SO2 emissions at the Illinois Plants. The agreement has been embodied in rule language, called the Combined Pollutant Standard, or CPS, and Midwest Generation's obligations under the agreement were conditioned upon the formal adoption of the CPS as an Illinois rule. On January 5, 2007, the Illinois EPA and Midwest Generation jointly filed the CPS in the pending state rulemaking related to the Illinois SIP for the CAIR. The CPS was approved by the Joint Committee on Administrative Rules on August 14, 2007, and became final upon publication in the Illinois Register, which took place on September 7, 2007. Midwest Generation believes that the CPS will provide greater predictability of the timing and amount of emissions reductions which will be required of the Illinois Plants for these pollutants through 2018.

Under the agreement, Midwest Generation will be required to achieve specified emissions reductions through a combination of environmental retrofits or unit shutdowns. The agreement contemplates three phases with each phase relating to one of the pollutants involved. Capital expenditures will be required for each phase.

The first phase involves installing activated carbon injection technology in 2008 and 2009 for the removal of mercury, a technology which EME has been testing at some of its plants. Capital expenditures relating to these controls are currently estimated to be approximately $60 million.

The second phase requires the installation of additional controls by the end of 2011 to further reduce NOx emissions from units to be determined by Midwest Generation in order to achieve an agreed-on fleetwide level of NOx emissions per million British thermal units (Btu). Capital expenditures for these controls are currently estimated to be approximately $450 million.

Thereafter, during the third phase of the plan, the focus will be on the reduction of SO2 emissions. Midwest Generation will be required either to place controls on several units at the Illinois Plants between 2012 and 2018 for this purpose or to remove them from service. Midwest Generation will consider many factors in making this choice including, among others, an assessment of the cost and performance of environmental technologies and equipment, the remaining estimated useful life of each affected unit and the market outlook for the prices of various commodities including electrical energy and capacity, coal and natural gas. In view of the many factors involved, Midwest Generation has not yet determined what actions it may take at each affected unit to provide for optimal compliance with the agreement during its third phase. At this time, however, additional capital expenditures during the third phase of the plan are estimated as being in the range of approximately $2.2 billion to $2.9 billion, depending on the number of units on which controls are placed versus the number which are removed from service. For the reasons described above, actual capital expenditures may vary substantially from the above estimates.

On May 30, 2006, the Illinois EPA submitted a proposed regulation to the Illinois Pollution Control Board to implement the Illinois SIP required for compliance with the CAIR. As noted previously, on January 5, 2007, the Illinois EPA and Midwest Generation filed the CPS in the pending Illinois CAIR rulemaking. The Illinois CAIR rule, along with the CPS, was approved by the Joint Committee on Administrative Rules on August 14, 2007. Both rules became final upon publication in the Illinois Register, which took place on September 7, 2007.

Pennsylvania

The Pennsylvania Environmental Quality Board accepted the Pennsylvania Department of Environmental Protection's (PADEP's) proposed SIP to implement the CAIR on February 20, 2007. The SIP is very similar to the Federal CAIR with modest NOx set asides for generation from renewables and waste coal. A final rule is expected in late 2007. At this time EME plans to comply with the proposal using existing pollution control equipment supplemented with the purchase of SO2 credits for the first phase of the rule which is effective in 2010.

Mercury Regulation

The Clean Air Mercury Rule (CAMR), published in the Federal Register on May 18, 2005, creates a market-based cap-and-trade program to reduce nationwide utility emissions of mercury in two distinct phases. In the first phase of the program, which will come into effect in 2010, the annual nationwide cap will be 38 tons. Emissions of mercury are to be reduced primarily by taking advantage of mercury reductions achieved by reducing SO2 and NOx emissions under the CAIR. In the second phase, which is to take effect in 2018, coal-fired power plants will be subject to a lower annual cap, which will reduce emissions nationwide to 15 tons. States may join the trading program by adopting the CAMR model trading rule in state regulations, or they may adopt regulations that mirror the necessary components of the model trading rule. States are not required to adopt a cap-and-trade program and may promulgate alternative regulations, such as command and control regulations, that are equivalent to or more stringent than the CAMR's suggested cap-and-trade program. Any program adopted by a state must be approved by the US EPA.

Contemporaneous with the adoption of the CAMR, the US EPA rescinded its previous finding that mercury emissions from coal-fired power plants had to be regulated as a hazardous air pollutant pursuant to Section 112 of the federal Clean Air Act, which would have imposed technology-based standards. Both the US EPA's rescission action and the CAMR are being challenged in the courts. Because EME cannot predict the outcome of these challenges, which could result in changes to the CAMR rules and timetables, the full impact of this regulation currently cannot be assessed.

Illinois

The final state rule for the reduction of mercury emissions in Illinois was adopted and became effective on December 21, 2006. The rule requires a 90% reduction of mercury emissions from coal-fired power plants averaged across company-owned Illinois stations and a minimum reduction of 75% for individual generating sources by July 1, 2009. The rule requires each station to achieve a 90% reduction by January 1, 2014 and, because emissions are measured on a rolling 12-month average, stations must install equipment necessary to meet the January 1, 2014, 90% reduction by January 1, 2013. Buying or selling of emission allowances under the federal CAMR cap and trade program would be prohibited.

Midwest Generation's CPS supersedes this rule for the Illinois Plants. The CPS requires installation of activated carbon injection technology for the removal of mercury on all Midwest

Generation units by July 2009 (except for three units to be shut down by the end of 2010), prohibits participation in the federal cap-and-trade program, and requires a 90% removal of mercury by unit by the end of 2015. While its CPS is pending, Midwest Generation has filed an appeal of the state's mercury rule that would require a 90% fleetwide reduction in mercury emissions by July 2009.

Pennsylvania

On February 17, 2007, the PADEP published in the Pennsylvania Bulletin regulations that would require coal-fired power plants to reduce mercury emissions by 80% by 2010 and 90% by 2015. The rule does not allow the use of emissions trading to achieve compliance. The rule became final upon publication.

At this time EME expects the Homer City facilities to achieve compliance by the 2010 deadline with mercury removal achieved by an existing flue gas desulfurization system on one generating unit and by sorbent injection on the other two units. EME has deferred making commitments for the installation of further environmental controls at the Homer City facilities at this time, but continues to study available environmental control technologies and estimated costs to reduce SO2 and mercury and to monitor developments related to mercury and other environmental regulations.

Ambient Air Quality Standards

The US EPA designated non-attainment areas for its 8-hour ozone standard on April 30, 2004, and for its fine particulate matter standard on January 5, 2005. Almost all of EME's facilities are located in counties that have been identified as being in non-attainment with both standards. States are required to revise their SIPs for the ozone and particulate matter standards within three years of the effective date of the respective non-attainment designations. The revised SIPs are likely to require additional emission reductions from facilities that are significant emitters of ozone precursors and particulates. Any additional obligations on EME's facilities to further reduce their emissions of SO2, NOx and fine particulates to address local non-attainment with the 8-hour ozone and fine particulate matter standards will not be known until the states revise their SIPs. Depending upon the final standards that are adopted, EME may incur substantial costs or experience other financial impacts resulting from required capital improvements or operational changes.

On September 22, 2006 the US EPA issued a final rule that implements the revisions to its fine particulate standard originally proposed on January 17, 2006. Under the new rule, the annual standard remains the same but the 24-hour fine particulate standard is significantly more stringent. The rule may require states to impose further emission reductions beyond those necessary to meet the existing standards. EME anticipates that any such further emissions reduction obligations would not be imposed under this standard until 2015 at the earliest, and intends to consider such rules as part of its overall plan for environmental compliance.

Illinois

Beginning with the 2003 ozone season (May 1 through September 30), EME has been required to comply with an average NOx emission rate of 0.25 lb NOx/MMBtu of heat input. This limitation is commonly referred to as the East St. Louis State Implementation Plan. This regulation is a State of Illinois requirement. Each of the Illinois Plants complied with this standard in 2004. Beginning with the 2004 ozone season, the Illinois Plants became subject to the federally mandated "NOx SIP Call" regulation that provided ozone-season NOx emission allowances to a 19-state region east of the Mississippi. This program provides for NOx allowance trading similar to the SO2 (acid rain) trading program already in effect.

During 2004, the Illinois Plants stayed within their NOx allocations by augmenting their allocation with early reduction credits generated within the fleet. In 2005, the Illinois Plants used banked allowances, along with some purchased allowances, to stay within their NOx allocations. In 2006, the Illinois Plants used purchased allowances to stay within their NOx allocations. Midwest Generation plans to continue to purchase allowances as it implements the agreement it reached with the Illinois EPA.

The Illinois EPA has begun to develop SIPs to meet National Ambient Air Quality Standards for 8-hour ozone and fine particulates with the intent of bringing non-attainment areas, such as Chicago, into attainment. The SIPs are expected to deal with all emission sources, not just power generators, and to address emissions of NOx, SO2, and volatile organic compounds. The SIP for 8-hour ozone was to be submitted to the US EPA by June 15, 2007, but is currently expected to be submitted later in the year. The SIP for fine particulates is to be submitted to the US EPA by April 5, 2008.

Midwest Generation's agreement with the Illinois EPA and the pending CPS include emission controls that will contribute to ozone and fine particulate attainment. Midwest Generation expects, but cannot guarantee, that the reductions required under the agreement and the pending CPS will be sufficient for compliance with future ozone and particulate matter regulations. See " Clean Air Act Illinois" for further discussion.

Pennsylvania

The Homer City facilities comply with current ozone requirements due to the selective catalytic reduction systems installed at each unit. Particulate requirements are met using a combination of scrubber reductions from Unit 3 and the purchase of SO2 allowances. Pennsylvania has not yet proposed new regulations to implement the National Ambient Air Quality Standards for 8-hour ozone or for fine particulates. These SIPs are to be submitted to US EPA by June 15, 2007 and April 5, 2008, respectively. Although the final form of the SIPs is not yet known, at this time EME anticipates that current treatment will be sufficient to meet the SIP requirements for 8-hour ozone, and that the SIP for fine particulates will require the continued use of the existing scrubber supplemented by the purchase of SO2 allowances.

Regional Haze

The goal of the 1999 regional haze regulations is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions in 60 years. Sources such as power plants that are reasonably anticipated to contribute to visibility impairment in Class I areas may be required to install best available retrofit technology (BART) or implement other control strategies to meet regional haze control requirements. States are required to revise their SIPs to demonstrate reasonable further progress towards meeting regional haze goals. Emission reductions achieved through other ongoing control programs may be sufficient to demonstrate reasonable progress toward the long-term goal, particularly for the first 10 to 15 year phase of the program. States must develop SIPs by December 2007. It is possible that sources subject to the CAIR will be able to satisfy their obligations under the regional haze regulations through compliance with the CAIR. However, until the SIPs are revised, EME cannot predict whether it will be required to install BART or implement other control strategies, and cannot identify the financial impacts of any additional control requirements.

The CPS, discussed above in " Clean Air Act Illinois," addresses emissions reductions at BART affected sources. In Pennsylvania, the PADEP considers the CAIR to meet the BART requirements, and the Homer City facilities are only required to consider reductions in emissions of suspended particulate matter (PM10), which at this time have not been developed by the state.

New Source Review Requirements

Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address Clean Air Act New Source Review (NSR) compliance issues at the nation's coal-fired power plants. The NSR regulations impose certain requirements on facilities, such as electric generating stations, in the event that modifications are made to air emissions sources at a facility. The US EPA's strategy included both the filing of a number of suits against power plant owners, and the issuance of a number of administrative notices of violation to power plant owners alleging NSR violations.

Prior to EME's purchase of the Homer City facilities, the US EPA requested information under Section 114 of the Clean Air Act from the prior owners of the plant concerning physical changes at the plant. This request was part of the US EPA's industry-wide investigation of compliance by coal-fired plants with the Clean Air Act NSR requirements. On February 21, 2003, Midwest Generation received a request for information under Section 114 regarding past operations, maintenance and physical changes at the Illinois Plants from the US EPA. On July 28, 2003, Commonwealth Edison received a substantially similar request for information from the US EPA related to the same plants. In a request dated February 1, 2005, the US EPA submitted a request for additional information to Midwest Generation. Midwest Generation has provided responses to these requests.

On July 31, 2007, the US EPA issued a NOV to Midwest Generation and Commonwealth Edison with respect to alleged violations of the Clean Air Act and certain opacity and particulate matter standards. See " Contractual Obligations, Commitments and Contingencies Contingencies Midwest Generation Potential Environmental Proceeding" for further discussion.

Water Quality Regulation

Clean Water Act Cooling Water Intake Structures

On July 9, 2004, the US EPA published the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures at existing large power plants. The purpose of the regulation was to reduce substantially the number of aquatic organisms that are pinned against cooling water intake structures or drawn into cooling water systems. Pursuant to the regulation, a demonstration study was required when applying for a new or renewed National Pollutant Discharge Elimination System (NPDES) wastewater discharge permit. If one could demonstrate that the costs of meeting the presumptive standards set forth in the regulation were significantly greater than the costs that the US EPA assumed in its rule making or are significantly disproportionate to the expected environmental benefits, a site-specific analysis could be performed to establish alternative standards. Depending on the findings of the demonstration studies, cooling towers and/or other mechanical means of reducing impingement and entrainment of aquatic organisms could have been required.

On July 9, 2007, the US EPA published in the Federal Register a notice immediately suspending the requirements for cooling water intake structures, pending further rulemaking. The US EPA is expected to begin another rulemaking process in October 2007. EME had begun to collect impingement and entrainment data at its potentially affected Midwest Generation facilities in Illinois to begin the process of determining what corrective actions might need to be taken under the previous rule, and those activities are continuing. Although the rule to be generated in the new rulemaking process could have a material impact on EME's operations, its compliance criteria have not yet been finalized, and EME cannot reasonably determine the financial impact at this time.

Illinois

The Illinois EPA is reviewing the water quality standards for the Des Plaines River adjacent to the Joliet Station and immediately downstream of the Will County Station to determine if the use classification should be upgraded. If the existing use classification is changed, the limits on the temperature of the discharges from the Joliet and Will County plants may be made more stringent. The Illinois EPA has also begun a review of the water quality standards for the Chicago River and Chicago Sanitary and Ship Canal which are adjacent to the Fisk and Crawford Stations. Proposed changes to the existing standards are still being developed. Accordingly, EME is not able to estimate the financial impact of potential changes to the water quality standards. However, the cost of additional cooling water treatment, if required, could be substantial.

Pennsylvania

The discharge from the treatment plant receiving the wastewater stream from EME's Unit 3 flue gas desulfurization system at the Homer City facilities has exceeded the stringent water-quality based limits for selenium in the station's NPDES permit. As a result, EME was notified in April 2002 by the PADEP that it was included in the Quarterly Noncompliance Report submitted to the US EPA. With the PADEP's approval, EME has undertaken a pilot program utilizing biological treatment. EME Homer City and the PADEP have entered into a consent order and agreement related to selenium discharge, which was filed in Pennsylvania state court on July 17, 2007. Under the consent order and agreement, EME Homer City agreed to pay a civil penalty of $200,000 and to install modifications to its wastewater system to achieve consistent compliance with discharge limits. Until the pilot programs have been completed and the treatment system design has been finalized, EME will be unable to estimate the costs for ongoing treatment.

Environmental Remediation

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at that facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury, natural resource damages, and investigation and remediation costs incurred by these parties in connection with these releases or threatened releases. In addition, persons who arrange for the disposal or treatment of hazardous or toxic substances at a disposal or treatment facility may be liable for the costs to remediate releases of hazardous substances from such facilities even where the disposal of such wastes was undertaken in compliance with applicable laws. Many of these laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, commonly referred to as CERCLA, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under these laws to be strict and joint and several.

With respect to EME's potential liabilities arising under CERCLA or similar laws for the investigation and remediation of contaminated property, EME accrues a liability to the extent the costs are probable and can be reasonably estimated. Midwest Generation has accrued approximately $4 million at June 30, 2007 for estimated environmental investigation and remediation costs for the Illinois Plants. This estimate is based upon the number of sites, the scope of work and the estimated costs for environmental activity where such expenditures could be reasonably estimated. Future estimated costs may vary based on changes in regulations or requirements of federal, state, or local governmental agencies, changes in technology, and actual costs of disposal. In addition, future remediation costs will be affected by the nature and extent of contamination discovered at the sites that requires remediation. Given the prior history of the operations at its facilities, EME cannot be certain that the existence or extent of all contamination at its sites has been fully identified. However, based on available information, management believes that future costs in excess of the amounts disclosed on all known and quantifiable environmental contingencies will not be material to EME's financial position.

Federal, state and local laws, regulations and ordinances also govern the removal, encapsulation or disturbance of asbestos-containing materials when these materials are in poor condition or in the event of construction, remodeling, renovation or demolition of a building. Those laws and regulations may impose liability for release of asbestos-containing materials and may provide for the ability of third parties to seek recovery from owners or operators of these properties for personal injury associated with asbestos-containing materials. In connection with the ownership and operation of its facilities, EME may be liable for these costs. EME has agreed to indemnify the sellers of the Illinois Plants and the Homer City facilities with respect to specified environmental liabilities. See " Contractual Obligations, Commitments and Contingencies Commercial Commitments Guarantees and Indemnities" for a discussion of these indemnities.

Climate Change

To date, the United States has chosen to pursue a voluntary greenhouse gas emissions reduction program to meet its obligations as a signatory to the United Nations Framework Convention on Climate Change. Currently a number of bills are proposed or under discussion in Congress to mandate reductions of greenhouse gas emissions. At this point, EME is unable to determine whether any of these proposals will be enacted into law or to estimate their potential effect on EME.

On April 2, 2007, the United States Supreme Court issued an opinion in *Massachusetts et. al. v. Environmental Protection Agency, et. al.*, ruling that US EPA has the authority to regulate greenhouse gas emissions of new motor vehicles under the Clean Air Act and that it has a duty to (i) determine whether greenhouse gas emissions of new motor vehicles contribute to climate change or (ii) offer a reasoned explanation for its failure to make such a determination when presented with a request for a rulemaking on the issue by the state claimants. The Court ruled that US EPA's failure to make the necessary determination or offer a reasonable explanation for its refusal to do so was impermissible. While this case hinged on a provision of the Clean Air Act related to emissions of motor vehicles, a parallel provision of the Clean Air Act applies to stationary sources such as electric generators. EME believes that the Court's *Massachusetts* decision may spur additional congressional action to require reductions of greenhouse gas emissions by all material sources, including electric generators.

There have been petitions from states and other parties to compel the US EPA to regulate greenhouse gases under the CAIR. Also, in 2004, several states and environmental organizations brought a complaint in federal court in New York, alleging that several electric utility corporations are jointly and severally liable under a theory of public nuisance for damages caused by the alleged contribution to global warming resulting from carbon dioxide emissions from coal-fired power plants owned and operated by these companies or their subsidiaries. Neither EME nor its subsidiaries were named as defendants in the complaint. The case was dismissed and is currently on appeal with the United States Court of Appeals for the Second Circuit.

In April 2006, private citizens brought a complaint in federal court in Mississippi against numerous defendants, including several electric utilities, arguing that emissions from the defendants' facilities contributed to climate change and seeking monetary damages related to the 2005 hurricane season. On December 19, 2006, the plaintiffs sought permission from the court to file an amended complaint naming approximately one hundred new defendants, including EME and three of its subsidiaries. The court has not yet ruled on the plaintiffs' motion.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap and trade greenhouse gas program for electric generators, referred to as the Regional Greenhouse Gas Initiative (RGGI). In August 2006, the participating states issued a model rule to be used as a basis for individual state legislative and regulatory action to implement the program. Illinois and Pennsylvania are not signatories to the RGGI, although Pennsylvania has participated as an observer of the process. Recent reports indicate that Pennsylvania is planning to announce a climate change policy that may include joining the RGGI. If Pennsylvania were to join the RGGI, this could have a material impact on EME's Homer City facilities.

In September 2006, California's Governor Schwarzenegger signed two bills into law regarding greenhouse gas emissions. The first, known as AB 32 or the California Global Warming Solutions Act of 2006, establishes a comprehensive program of regulatory and market mechanisms to achieve reductions of greenhouse gases. AB 32 requires the California Air Resources Board to develop regulations and market mechanisms targeted to reduce California's greenhouse gas emissions to 1990 levels by 2020. California Air Resources Board's mandatory program will take effect commencing 2012 and will implement incremental reductions so that greenhouse gas emissions will be reduced to 1990 levels by 2020. The second bill, known as SB 1368, requires the California Public Utilities Commission and the California Energy Commission to adopt greenhouse gas emissions performance standards for investor owned and publicly owned utilities, respectively, for long-term procurement of electricity. The standards must equal the performance of a combined-cycle gas turbine generator. The California Public Utilities Commission adopted such a standard on January 25, 2007 (which limits emissions to 1,100 pounds of carbon dioxide per MWh). On May 28, 2007, the California Energy Commission adopted regulations pursuant to SB 1368 establishing and implementing greenhouse gas emissions performance standards for baseload generation of local publicly owned electric utilities. These regulations were submitted to the Office of Administrative Law on June 1, 2007 and were subsequently disapproved. On August 29, 2007, the California Energy Commission adopted revised regulations, which are currently pending before the Office of Administrative Law. In addition, the California Public Utilities Commission is addressing climate change related issues in various regulatory proceedings. At this time, EME believes that all of its facilities in California meet the greenhouse gas emissions performance standard contemplated by SB 1368, but EME will continue to monitor both regulations, as they are developed, for potential impact on its existing facilities and its projects under development.

The ultimate outcome of the climate change debate could have a significant economic effect on EME. Any legal obligation that would require EME to reduce substantially its emissions of carbon dioxide or would impose additional costs or charges for the emission of carbon dioxide could have a materially adverse effect on EME.

MARKET RISK EXPOSURES

Introduction

EME's primary market risk exposures are associated with the sale of electricity and capacity from and the procurement of fuel for its merchant power plants. These market risks arise from fluctuations in electricity, capacity and fuel prices, emission allowances, and transmission rights. Additionally, EME's financial results can be affected by fluctuations in interest rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures.

Commodity Price Risk

Overview

EME's revenues and results of operations of its merchant power plants will depend upon prevailing market prices for capacity, energy, ancillary services, emission allowances or credits, coal, natural gas and fuel oil, and associated transportation costs in the market areas where EME's merchant plants are located. Among the factors that influence the price of energy, capacity and ancillary services in these markets are:

- prevailing market prices for coal, natural gas and fuel oil, and associated transportation;
- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities and/or technologies that may be able to produce electricity at a lower cost than EME's generating facilities and/or increased access by competitors to EME's markets as a result of transmission upgrades;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the market structure rules established for each market area and regulatory developments affecting the market areas, including any price limitations and other mechanisms adopted to address volatility or illiquidity in these markets or the physical stability of the system;
- the cost and availability of emission credits or allowances;
- the availability, reliability and operation of competing power generation facilities, including nuclear generating plants, where applicable, and the extended operation of such facilities beyond their presently expected dates of decommissioning;
- weather conditions prevailing in surrounding areas from time to time; and
- changes in the demand for electricity or in patterns of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs.

A discussion of commodity price risk for the Illinois Plants and the Homer City facilities is set forth below.

Introduction

EME's merchant operations expose it to commodity price risk, which represents the potential loss that can be caused by a change in the market value of a particular commodity. Commodity price risks are actively monitored by a risk management committee to ensure compliance with EME's risk management policies. Policies are in place which define risk management processes, and procedures exist which allow for monitoring of all commitments and positions with regular reviews by EME's risk management committee. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

In addition to prevailing market prices, EME's ability to derive profits from the sale of electricity will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the units is expected to vary.

EME uses "value at risk" to identify, measure, monitor and control its overall market risk exposure in respect of its Illinois Plants, its Homer City facilities, and its trading positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify the risk factors. Value at risk measures the possible loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and relying on a single risk measurement tool, EME supplements this approach with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss limits and counterparty credit exposure limits.

Hedging Strategy

To reduce its exposure to market risk, EME hedges a portion of its merchant portfolio risk through EMMT, an EME subsidiary engaged in the power marketing and trading business. To the extent that EME does not hedge its merchant portfolio, the unhedged portion will be subject to the risks and benefits of spot market price movements. Hedge transactions are primarily implemented through:

- the use of contracts cleared on the Intercontinental Trading Exchange and the New York Mercantile Exchange,
- forward sales transactions entered into on a bilateral basis with third parties, including electric utilities and power marketing companies,
- full requirements services contracts or load requirements services contracts for the procurement of power for electric utilities' customers, with such services including the delivery of a bundled product including, but not limited to, energy, transmission, capacity, and ancillary services, generally for a fixed unit price, and
- participation in capacity auctions.

The extent to which EME enters into contracts to hedge its market price risk depends on several factors. First, EME evaluates over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with fluctuating spot market sales. Second, EME's ability to enter into hedging transactions depends upon its and Midwest Generation's credit capacity and upon the forward sales markets having sufficient liquidity to enable EME to identify appropriate counterparties for hedging transactions.

In the case of hedging transactions related to the generation and capacity of the Illinois Plants, Midwest Generation is permitted to use its working capital facility and cash on hand to provide credit support for these hedging transactions entered into by EMMT under an energy services agreement between Midwest Generation and EMMT. Utilization of this credit facility in support of hedging transactions provides additional liquidity support for implementation of EME's contracting strategy for the Illinois Plants. In addition, Midwest Generation is permitted to grant liens on its property in support of eligible hedging transactions associated with the Illinois Plants. In the case of hedging transactions related to the generation and capacity of the Homer City facilities, credit support is provided by EME pursuant to intercompany arrangements between it and EMMT. See " Credit Risk" below.

Energy Price Risk Affecting Sales from the Illinois Plants

All the energy and capacity from the Illinois Plants is sold under terms, including price and quantity, arranged by EMMT with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. As discussed further below, power generated at the Illinois Plants is generally sold into the PJM market.

Midwest Generation sells its power into PJM at spot prices based upon locational marginal pricing. Hedging transactions related to the generation of the Illinois Plants are generally entered into at the Northern Illinois Hub in PJM, and may also be entered into at other trading hubs, including the AEP/Dayton Hub in PJM and the Cinergy Hub in the Midwest Independent Transmission System Operator (MISO). These trading hubs have been the most liquid locations for hedging purposes. However, hedging transactions which settle at points other than the Northern Illinois Hub are subject to the possibility of basis risk. See " Basis Risk" below for further discussion.

PJM has a short-term market, which establishes an hourly clearing price. The Illinois Plants are situated in the PJM control area and are physically connected to high-voltage transmission lines serving this market.

The following table depicts the average historical market prices for energy per megawatt-hour during 2006, 2005 and 2004 and during the first six months of 2007.

	2007(1)	2006(1)	2005(1)	2004
January	$ 35.75	$ 42.27	$ 38.36	$ 27.88(2)
February	56.64	42.66	34.92	29.98(2)
March	42.04	42.50	45.75	30.66(2)
April	48.91	43.16	38.98	27.88(2)
May	44.49	39.96	33.60	34.05(1)
June	39.76	34.80	42.45	28.58(1)
Six-Month Average	$ 44.60	$ 40.89		
July		51.82	50.87	30.92(1)
August		54.76	60.09	26.31(1)
September		31.87	53.30	27.98(1)
October		37.80	49.39	30.93(1)
November		41.90	44.03	29.15(1)
December		33.57	64.99	29.90(1)
Yearly Average		$ 41.42	$ 46.39	$ 29.52

(1) Represents average historical market prices for energy as quoted for sales into the Northern Illinois Hub. Energy prices were calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM.

(2) Represents average historical market prices for energy "Into ComEd." Energy prices were determined by obtaining broker quotes and other public price sources for "Into ComEd" delivery points.

Forward market prices at the Northern Illinois Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand (which in turn is affected by weather, economic growth, and other factors), plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the Illinois Plants into these markets may vary materially from the forward market prices set forth in the table below.

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the Northern Illinois Hub at June 30, 2007:

		24-Hour Northern Illinois Hub Forward Energy Prices(1)
2007		
July	$	45.87
August		50.61
September		37.31
October		36.18
November		38.48
December		44.63
2008 Calendar "strip"(2)	$	46.09

(1) Energy prices were determined by obtaining broker quotes and information from other public sources relating to the Northern Illinois Hub delivery point.

(2) Market price for energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub.

The following table summarizes Midwest Generation's hedge position (primarily based on prices at the Northern Illinois Hub) at June 30, 2007:

		2007		2008		2009
Energy Only Contracts(1)						
MWh		8,250,150		10,837,600		2,048,000
Average price/MWh(2)	$	48.07	$	61.38	$	60.00
Load Requirements Services Contracts						
Estimated MWh(3)		4,071,803		5,613,433		1,631,859
Average price/MWh(4)	$	64.35	$	64.01	$	63.65
Total estimated MWh		12,321,953		16,451,033		3,679,859

(1) Primarily at Northern Illinois Hub.

(2) The energy only contracts include forward contracts for the sale of power and futures contracts during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at June 30, 2007 is not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

(3) Under a load requirements services contract, the amount of power sold is a portion of the retail load of the purchasing utility and thus can vary significantly with variations in that retail load. Retail load depends upon a number of factors, including the time of day, the time of the year and the utility's number of new and continuing customers. Estimated MWh have been forecast based on historical patterns and on assumptions regarding the factors that may affect retail loads in the future. The actual load will vary from that used for the above estimate, and the amount of variation may be material.

(4) The average price per MWh under a load requirements services contract (which is subject to a seasonal price adjustment) represents the sale of a bundled product that includes, but is not limited to, energy, capacity and ancillary services. Furthermore, as a supplier of a portion of a utility's load, Midwest Generation will incur charges from PJM as a load-serving entity. For these reasons, the average price per MWh under a load requirements services contract is not comparable to the sale of power under an energy only contract. The average price per MWh under a load requirements services contract represents the sale of the bundled product based on an estimated customer load profile.

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Subsequent to June 30, 2007, we entered into additional hedges for approximately 3.3 terawatt-hours (TWh) for each of 2009 and 2010 at average prices of $64.78/MWh and $63.12/MWh, respectively, for the Illinois Plants.

Energy Price Risk Affecting Sales from the Homer City Facilities

All the energy and capacity from the Homer City facilities is sold under terms, including price and quantity, arranged by EMMT with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. Electric power generated at the Homer City facilities is generally sold into the PJM market. PJM has a short-term market, which establishes an hourly clearing price. The Homer City facilities are situated in the PJM control area and are physically connected to high-voltage transmission lines serving both the PJM and New York Independent System Operator (NYISO) markets.

The following table depicts the average historical market prices for energy per megawatt-hour at the Homer City busbar and in PJM West Hub (EME Homer City's primary trading hub) during 2006, 2005, 2004 and during the first six months of 2007:

Historical Energy Prices(1)
24-Hour PJM

	Homer City Busbar				PJM West Hub			
	2007	**2006**	**2005**	**2004**	**2007**	**2006**	**2005**	**2004**
January	$ 40.30	$ 48.67	$ 45.82	$ 51.12	$ 44.63	$ 54.57	$ 49.53	$ 55.01
February	64.27	49.54	39.40	47.19	73.93	56.39	42.05	44.22
March	55.00	53.26	47.42	39.54	61.02	58.30	49.97	39.21
April	52.42	48.50	44.27	43.01	58.74	49.92	44.55	42.82
May	48.12	44.71	43.67	44.68	53.89	48.55	43.64	48.04
June	45.88	38.78	46.63	36.72	60.19	45.78	53.72	38.05
Six-Month Average	$ 51.00	$ 47.24			$ 58.73	$ 52.25		
July		53.68	54.63	40.09		63.47	66.34	43.64
August		58.60	66.39	34.76		76.57	82.83	38.59
September		33.26	66.67	40.62		34.40	76.82	41.96
October		37.42	67.93	37.37		39.65	77.56	37.78
November		40.13	59.78	35.79		44.83	62.01	36.91
December		35.29	75.03	38.59		40.53	81.97	41.83
Yearly Average		$ 45.15	$ 54.80	$ 40.79		$ 51.08	$ 60.92	$ 42.34

(1) Energy prices were calculated at the Homer City busbar (delivery point) and PJM West Hub using historical hourly real-time prices provided on the PJM web-site.

Forward market prices at the PJM West Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand (which in turn is affected by weather, economic growth and other factors), plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the Homer City facilities into these markets may vary materially from the forward market prices set forth in the table below.

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the PJM West Hub at June 30, 2007:

	24-Hour PJM West Hub Forward Energy Prices(1)
2007	
July	$ 64.02
August	69.02
September	49.57
October	48.52
November	50.71
December	57.24
2008 Calendar "strip"(2)	$ 62.36

(1) Energy prices were determined by obtaining broker quotes and information from other public sources relating to the PJM West Hub delivery point. Forward prices at PJM West Hub are generally higher than the prices at the Homer City busbar.

(2) Market price for energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub.

The following table summarizes Homer City's hedge position at June 30, 2007:

	2007	2008	2009
MWh	3,820,375	7,232,000	2,048,000
Average price/MWh(1)	$ 64.24	$ 60.86	$ 71.05

(1) The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at June 30, 2007 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

Subsequent to June 30, 2007, we entered into additional hedges for approximately 1.0 TWh for each of 2009 and 2010 at average prices of $80.81/MWh and $77.80/MWh, respectively, for the Homer City facilities.

The average price/MWh for EME Homer City's hedge position is based on PJM West Hub. Energy prices at the Homer City busbar have been lower than energy prices at the PJM West Hub. See " Basis Risk" below for a discussion of the difference.

Capacity Price Risk

On June 1, 2007, PJM implemented the reliability pricing model (RPM) for capacity. The purpose of the RPM is to provide a long-term pricing signal for capacity resources. The RPM allows PJM to satisfy the region's need for generation capacity, which is then allocated among the load-serving entities through a locational reliability charge.

The first RPM auction took place in April 2007 and resulted in a fixed price for Midwest Generation and EME Homer City's capacity sold into the auction (included in PJM as "rest of market" location) of $40.80/MW per day for the period from June 1, 2007 through May 31, 2008. The second auction took place in July 2007 and resulted in a fixed price for Midwest Generation and EME Homer City's capacity sold into the auction of $111.92/MW per day for the period from June 1, 2008 through May 31, 2009. Subsequent auctions will be conducted in October 2007 and January 2008 to auction capacity for periods through May 2011.

Midwest Generation entered into hedge transactions in advance of the RPM auctions with counterparties that are settled through PJM. In addition, the load service requirements contracts entered into by Midwest Generation with Commonwealth Edison include energy, capacity and ancillary services (sometimes referred to as a "bundled product"). Under PJM's business rules, Midwest Generation sells all of its available capacity (unit capacity less forced outages) into the RPM and is subject to a locational reliability charge for the load under these contracts. This means that the locational reliability charge generally offsets the related amounts sold in the RPM, which Midwest Generation presents net in the table below.

Prior to the RPM auctions for the relevant delivery periods, EME Homer City sold a portion of its capacity to an unrelated third party for the delivery periods from June 1, 2007 through May 31, 2008 and June 1, 2008 through May 31, 2009. EME Homer City will not receive the RPM auction clearing price for this previously sold capacity. The price EME Homer City will receive for these capacity sales is a function of NYISO capacity clearing prices resulting from separate NYISO capacity auctions.

The following table summarizes the status of capacity sales for Midwest Generation and EME Homer City at July 27, 2007:

	July 1, 2007 to May 31, 2008		June 1, 2008 to May 31, 2009	
	Midwest Generation	EME Homer City	Midwest Generation	EME Homer City
Fixed Price Capacity Sales				
Through RPM Auction, Net				
MW	2,625	786	3,283	820
Price per MW-day	$ 40.80	$ 40.80	$ 111.92	$ 111.92
Non-unit Specific Capacity Sales				
MW	500		880	
Price per MW-day	$ 21.29		$ 64.35	
Variable Capacity Sales				
MW		870		881
Price per MW-day(1)		$ 69.39		$ 72.56

(1) Actual contract price is a function of NYISO capacity auction clearing prices. Expected price per MW-day is based on forward over-the-counter NYISO prices on July 27, 2007.

Revenues from the sale of capacity from Midwest Generation and EME Homer City beyond the periods set forth above will depend upon the amount of capacity available and future market prices either in PJM or nearby markets if EME has an opportunity to capture a higher value associated with those markets. Under PJM's RPM system, the market price for capacity is generally determined by aggregate market-based supply conditions and an administratively set aggregate demand curve. Among the factors influencing the supply of capacity in any particular market are plant forced outage rates, plant closings, plant delistings (due to plants being removed as capacity resources and/or to export capacity to other markets), capacity imports from other markets, and new entry.

Basis Risk

Sales made from the Illinois Plants and the Homer City facilities in the real-time or day-ahead market receive the actual spot prices or day-ahead prices, as the case may be, at the busbars (delivery points) of the individual plants. In order to mitigate price risk from changes in spot prices at the individual plant busbars, EME may enter into cash settled futures contracts as well as forward contracts with counterparties for energy to be delivered in future periods. Currently, a liquid market for entering into these contracts at the individual plant busbars does not exist. A liquid market does exist for a settlement point at the PJM West Hub in the case of the Homer City facilities and for a settlement point at the Northern Illinois Hub in the case of the Illinois Plants. EME's hedging activities use these settlement points (and, to a lesser extent, other similar trading hubs) to enter into hedging contracts. EME's revenues with respect to such forward contracts include:

- sales of actual generation in the amounts covered by the forward contracts with reference to PJM spot prices at the busbar of the plant involved, plus,

- sales to third parties at the price under such hedging contracts at designated settlement points (generally the PJM West Hub for the Homer City facilities and the Northern Illinois Hub for the Illinois Plants) less the cost of power at spot prices at the same designated settlement points.

Under PJM's market design, locational marginal pricing, which establishes market prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, can cause the price of a specific delivery point to be higher or lower relative to other locations depending on how the point is affected by transmission constraints. To the extent that, on the settlement date of a hedge contract, spot prices at the relevant busbar are lower than spot prices at the settlement point, the proceeds actually realized from the related hedge contract are effectively reduced by the difference. This is referred to as "basis risk." During the six months ended June 30, 2007, transmission congestion in PJM has resulted in prices at the Homer City busbar being lower than those at the PJM West Hub by an average of 13%, compared to 10% during the six months ended June 30, 2006, and 12% during 2006, compared to 10% during 2005 and 4% during 2004. The monthly average difference during the 12 months ended June 30, 2007 ranged from 3% to 24%. In contrast to the Homer City facilities, during the past 12 months, the prices at the Northern Illinois Hub were substantially the same as those at the individual busbars of the Illinois Plants.

By entering into cash settled futures contracts and forward contracts using the PJM West Hub and the Northern Illinois Hub (or other similar trading hubs) as settlement points, EME is exposed to basis risk as described above. In order to mitigate basis risk, EME may purchase financial transmission rights and basis swaps in PJM for EME Homer City. A financial transmission right is a financial instrument that entitles the holder to receive the difference of actual spot prices for two delivery points in exchange for a fixed amount. Accordingly, EME's hedging activities include using financial transmission rights alone or in combination with forward contracts and basis swap contracts to manage basis risk.

Coal Price Risk

The Illinois Plants and the Homer City facilities purchase coal primarily obtained from the Southern PRB of Wyoming and from mines located near the facilities in Pennsylvania, respectively. Coal purchases are made under a variety of supply agreements extending through 2010. The following table summarizes the amount of coal under contract at June 30, 2007 for the remainder of 2007 and the following three years.

	Amount of Coal Under Contract in Millions of Tons(1)			
	July through December 2007	2008	2009	2010
Illinois Plants	9.2	14.6	11.7	11.7
Homer City facilities	2.7	4.3	3.5	0.2

(1) The amount of coal under contract in tons is calculated based on contracted tons and applying an 8,800 Btu equivalent for the Illinois Plants and 13,000 Btu equivalent for the Homer City facilities.

EME is subject to price risk for purchases of coal that are not under contract. Prices of Northern Appalachian (NAPP) coal, which are related to the price of coal purchased for the Homer City facilities, decreased slightly in 2006 from 2005 year-end prices and increased considerably during 2005 and 2004. The price of NAPP coal (with 13,000 Btu per pound heat content and less than 3.0 pounds of SO2 per MMBtu sulfur content) fluctuated between $37.50 per ton and $45.00 per ton during 2006, with a price of $43.00 per ton at December 15, 2006, as reported by the Energy Information Administration. The 2006 decrease in the NAPP coal price was largely due to the combined effects of mild weather, easing natural gas prices and improving eastern stockpiles. In 2005, the price of NAPP coal fluctuated between $44.00 per ton and $57.00 per ton, with a price of $45.00 per ton at December 30, 2005, as reported by the Energy Information Administration. In 2004, the price of NAPP coal increased to more than $60.00 per ton from below $40.00 per ton in January 2004. The 2005 overall increase in the NAPP coal price was largely attributed to greater demand from domestic power producers and increased international shipments of coal to Asia. During the first six months of 2007, the price of NAPP coal increased to $45.15 per ton at June 29, 2007, as reported by the Energy Information Administration, which was in line with normal market price volatility.

Prices of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO2 per MMBtu sulfur content), which is purchased for the Illinois Plants decreased during 2006 from 2005 year-end prices due to easing natural gas prices, fuel switching, lower prices for SO2 allowances and improved inventory. Prices of PRB coal significantly increased in 2005 due to the curtailment of coal shipments during 2005 due to increased PRB coal demand from other regions (east), rail constraints, higher oil and natural gas prices and higher prices for SO2 allowances. The price of PRB coal decreased from $20.66 per ton in January 2006 to $9.90 per ton at December 15, 2006, as reported by the Energy Information Administration, which compares to 2005 prices that ranged from $6.20 per ton to $18.48 per ton and 2004 prices which were generally below $7 per ton. During the first six months of 2007, the price of PRB coal decreased to $9.15 per ton at June 29, 2007, as reported by the Energy Information Administration, due to continuing high stockpiles and oversupply of market.

Based on EME's anticipated coal requirements in 2007 in excess of the amount under contract, EME expects that a 10% change in the price of coal at December 31, 2006 would increase or decrease pre-tax income in 2007 by approximately $2 million.

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO2 allowances, and Illinois and Pennsylvania regulations implemented the federal NOX SIP Call requirement. As part of the acquisition of the Illinois Plants and the Homer City facilities, EME obtained the rights to the emission allowances that have been or are allocated to these plants. EME purchases (or sells) emission allowances based on the amounts required for actual generation in excess of (or less than) the amounts allocated under these programs.

The price of emission allowances, particularly SO2 allowances issued through the federal Acid Rain Program, decreased in 2006 from 2005 year-end prices and increased substantially during 2005 and 2004. The average price of purchased SO2 allowances was $664 per ton during 2006, $1,219 per ton during 2005, and $435 per ton during 2004. The decrease in the price of SO2 allowances during 2006 from 2005 year-end prices has been attributed to a decline in natural gas prices and fuel switching from oil to gas. The 2005 increase in the price of SO2 allowances had been attributed to reduced numbers of both allowance sellers and prior-year allowances. During the first six months of 2007, the average price of purchased SO2 allowances decreased to $517 per ton. The price of SO2 allowances, determined by obtaining broker quotes and information from other public sources was $544 per ton as of July 31, 2007.

Based on EME's anticipated SO2 emission allowances requirements in 2007, EME expects that a 10% change in the price of SO2 emission allowances at December 31, 2006 would increase or decrease pre-tax income in 2007 by approximately $2 million. See "Liquidity and Capital Resources Environmental Matters and Regulations" for a discussion of environmental regulations related to emissions.

Accounting for Energy Contracts

EME uses a number of energy contracts to manage exposure from changes in the price of electricity, including forward sales and purchases of physical power and forward price swaps which settle only on a financial basis (including futures contracts). EME follows SFAS No. 133, and under this Standard these energy contracts are generally defined as derivative financial instruments. Importantly, SFAS No. 133 requires changes in the fair value of each derivative financial instrument to be recognized in earnings at the end of each accounting period unless the instrument qualifies for hedge accounting under the terms of SFAS No. 133. For derivatives that do qualify for cash flow hedge accounting, changes in their fair value are recognized in other comprehensive income until the hedged item settles and is recognized in earnings. However, the ineffective portion of a derivative that qualifies for cash flow hedge accounting is recognized currently in earnings. For further discussion of derivative financial instruments, see "Management's Overview; Critical Accounting Policies Critical Accounting Policies Derivative Financial Instruments and Hedging Activities."

SFAS No. 133 affects the timing of income recognition, but has no effect on cash flow. To the extent that income varies under SFAS No. 133 from accrual accounting (i.e., revenue recognition based on settlement of transactions), EME records unrealized gains or losses. Unrealized SFAS No. 133 gains or losses result from:

- energy contracts that do not qualify for hedge accounting under SFAS No. 133 (which are sometimes referred to as economic hedges). Unrealized gains and losses include:
  - the change in fair value (sometimes called mark-to-market) of economic hedges that relate to subsequent periods, and
  - offsetting amounts to the realized gains and losses in the period non-qualifying hedges are settled.
- the ineffective portion of qualifying hedges which generally relate to changes in the expected basis between the sale point and the hedge point. Unrealized gains or losses include:
  - the current period ineffectiveness on the hedge program for subsequent periods. This occurs because the ineffective gains or losses are recorded in the current period, whereby the energy revenues related to generation being hedged will be recorded in the subsequent period along with the effective portion of the related hedge transaction, and
  - offsetting amounts to the realized ineffective gains and losses in the period cash flow hedges are settled.

EME classifies unrealized gains and losses from energy contracts as part of operating revenues. The results of derivative activities are recorded as part of cash flows from operating activities in the consolidated statements of cash flows. The following table summarizes unrealized gains (losses) from non-trading activities for the three-year period ended December 31, 2006 and for the second quarter of 2007 and six months ended June 30, 2007.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in millions)			
Non-qualifying hedges				
Illinois Plants	$ 4	$ 2	$ (18)	$ 10
Homer City	2	4	1	2
Ineffective portion of cash flow hedges				
Illinois Plants		(1)		1
Homer City	(5)	5	(3)	2
Total unrealized gains (losses)	$ 1	$ 10	$ (20)	$ 15

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Non-qualifying hedges			
Illinois Plants	$ 28	$ (17)	$ (4)
Homer City	2	(1)	1
Ineffective portion of cash flow hedges			
Illinois Plants	2	(2)	
Homer City	33	(40)	(14)
Total unrealized gains (losses)	$ 65	$ (60)	$ (17)

Fair Value of Financial Instruments

Non-Trading Derivative Financial Instruments

The following table summarizes the fair values for outstanding derivative financial instruments used in EME's continuing operations for purposes other than trading, by risk category (in millions):

	June 30, 2007	December 31, 2006	December 31, 2005
Commodity price:			
Electricity	$ 1	$ 184	$ (434)

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The decrease in fair value of electricity contracts at June 30, 2007 as compared to December 31, 2006 is attributable to an increase in the average market prices for power as compared to contracted prices at June 30, 2007, which is the valuation date. The increase in the fair value of electricity contracts in 2006 as compared to 2005 is attributable to a decline in the average market prices for power as compared to contracted prices at December 31, 2006, which is the valuation date. A 10% change in the market price at December 31, 2006 would increase or decrease the fair value of outstanding derivative commodity price

contracts by approximately $347 million. The following table summarizes the maturities and the related fair value, based on actively traded prices, of EME's commodity derivative assets and liabilities (in millions):

Prices Actively Quoted	Total Fair Value	Maturity less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity greater than 5 years
As of December 31, 2006	$ 184	$ 161	$ 23	$	$
As of June 30, 2007	$ 1	$ 43	$ (42)	$	$

Energy Trading Derivative Financial Instruments

The fair value of the commodity financial instruments related to energy trading activities as of June 30, 2007 and December 31, 2006 and 2005, are set forth below (in millions):

	June 30, 2007		December 31, 2006		December 31, 2005	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
Electricity	$ 142	$ 18	$ 313	$ 207	$ 127	$ 27
Other			5		1	
Total	$ 142	$ 18	$ 318	$ 207	$ 128	$ 27

The change in the fair value of trading contracts was as follows (in millions):

For the year ended December 31, 2006	
Fair value of trading contracts at January 1, 2006	$ 101
Net gains from energy trading activities	137
Amount realized from energy trading activities	(131)
Other changes in fair value	4
Fair value of trading contracts at December 31, 2006	$ 111
For the six months ended June 30, 2007	
Net gains from energy trading activities	65
Amount realized from energy trading activities	(58)
Other changes in fair value	6
Fair value of trading contracts at June 30, 2007	$ 124

A 10% change in the market price at December 31, 2006 would increase or decrease the fair value of trading contracts by approximately $2 million.

Quoted market prices are used to determine the fair value of the financial instruments related to energy trading activities, except for the power sales agreement with an unaffiliated electric utility that EME's subsidiary purchased and restructured and a long-term power supply agreement with another unaffiliated party. EME's subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using a discount rate equal to the cost of borrowing the non-recourse debt incurred to finance the purchase of the power supply agreement. The following table summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities (in millions):

	Total Fair Value	Maturity less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity greater than 5 years
As of December 31, 2006					
Prices actively quoted	$ 26	$ 26	$	$	$
Prices provided by other external sources	(1)	(1)			
Prices based on models and other valuation methods	86	4	13	18	51
Total	$ 111	$ 29	$ 13	$ 18	$ 51
As of June 30, 2007					
Prices actively quoted	$ 41	$ 37	$ 4	$	$
Prices based on models and other valuation methods	83	3	14	20	46
Total	$ 124	$ 40	$ 18	$ 20	$ 46

Credit Risk

In conducting EME's hedging and trading activities, EME contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with re-contracting the product at a price different from the original contracted price if the non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time a counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. EME measures, monitors and mitigates credit risk to the extent possible. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary. EME also takes other appropriate steps to limit or lower credit exposure. Processes have also been established to determine and monitor the creditworthiness of counterparties. EME manages the credit risk on the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. A risk management committee regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

The credit risk exposure from counterparties of merchant energy activities (excluding load requirements services contracts) are measured as either: (i) the sum of 60 days of accounts receivable, current fair value of open positions, and a credit value at risk, or (ii) the sum of delivered and unpaid accounts receivable and the current fair value of open positions. EME's subsidiaries enter into master agreements and other arrangements in conducting hedging and trading activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. Accordingly, EME's credit risk exposure from counterparties is based on net exposure under these agreements. At June 30, 2007, the amount of exposure as described above, broken down by the credit ratings of EME's counterparties, was as follows:

S&P Credit Rating	June 30, 2007
	(in millions)
A or higher	$ 19
A-	18
BBB+	80
BBB	31
BBB-	2
Below investment grade	
Total	$ 150

EME's plants owned by unconsolidated affiliates in which EME owns an interest sell power under power purchase agreements. Generally, each plant sells its output to one counterparty. Accordingly, a default by a counterparty under a power purchase agreement, including a default as a result of a bankruptcy, would likely have a material adverse effect on the operations of such power plant.

In addition, coal for the Illinois Plants and the Homer City facilities is purchased from suppliers under contracts which may be for multiple years. A number of the coal suppliers to the Illinois Plants and the Homer City facilities do not currently have an investment grade credit rating and, accordingly, EME may have limited recourse to collect damages in the event of default by a supplier. EME seeks to mitigate this risk through diversification of its coal suppliers and through guarantees and other collateral arrangements when available. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers.

EME's merchant plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transact capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 49% and 58% of EME's consolidated operating revenues for the six months ended June 30, 2007 and the year ended December 31, 2006, respectively. Moody's rates PJM's senior unsecured debt Aa3. PJM, an independent system operator with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At June 30, 2007, EME's account receivable due from PJM was $86 million.

Beginning in January 2007, EME also derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Illinois Plants to Commonwealth Edison under load requirements services contracts. Sales under these contracts accounted for 19% of EME's consolidated operating revenues during the six months ended June 30, 2007. Commonwealth Edison's senior unsecured debt rating was downgraded below investment grade by S&P in October 2006 and by Moody's in March 2007. As a result, Commonwealth Edison is required to pay EME twice a month for sales under these contracts. At June 30, 2007, EME's account receivable due from Commonwealth Edison was $21 million. Commonwealth Edison has stated that it would face possible bankruptcy if an electric rate freeze, which expired January 1, 2007, was re-introduced. In addition, the Illinois Attorney General and other parties have appeals pending before the Illinois Supreme Court pertaining to the Illinois Commerce Commission orders which authorized Commonwealth Edison and Ameren to procure power through a reverse auction process. On July 24, 2007, Midwest Generation and EMMT, along with other power generation companies and utilities, entered into a settlement agreement with the Illinois Attorney General. The settlement is subject to enacting legislation. See "Management's Overview; Critical Accounting Policies Management's Overview Illinois Settlement" for further discussion. EME is unable to predict whether the settlement agreement will be implemented as contemplated or that the legislation necessary for the settlement to become effective, or other policy changes affecting utility rates or procurement practices, will be enacted.

Interest Rate Risk

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EME mitigates the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. Based on the amount of variable rate long-term debt for which EME has not entered into interest rate hedge agreements at December 31, 2006, a 100-basis-point change in interest rates at December 31, 2006 would increase or decrease annual income before taxes by approximately $4 million. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of EME's total long-term obligations (including current portion) was $3.5 billion at December 31, 2006, compared to the carrying value of $3.2 billion. A 10% increase in market interest rates at December 31, 2006 would result in a decrease in the fair value of total long-term obligations by approximately $130 million. A 10% decrease in market interest rates at December 31, 2006 would result in an increase in the fair value of total long-term obligations by approximately $148 million.

The fair market value of EME's consolidated long-term obligations (including current portion) was $3.8 billion at June 30, 2007, compared to the carrying value of $4.0 billion.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to quantitative and qualitative disclosures about market risk is filed with this prospectus under "Management's Discussion and Analysis of Financial Condition and Results of Operations."

BUSINESS

The Company

EME is an independent power producer engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EME also conducts hedging and energy trading activities in power markets open to competition. EME is a wholly owned subsidiary of MEHC. Edison International is EME's ultimate parent company. Edison International also owns SCE, one of the largest electric utilities in the United States.

EME was formed in 1986 with two domestic operating power plants. As of June 30, 2007, EME's subsidiaries and affiliates owned or leased interests in 32 operating power plants with an aggregate net physical capacity of 10,670 MW of which EME's capacity pro rata share was 9,500 MW. At June 30, 2007, six projects totaling 293 MW of generating capacity were under construction.

Management and Organizational Changes

EME implemented management and organizational changes in 2005 to streamline its reporting relationships and eliminate its regional management structure. In addition, EME and its affiliate, Edison Capital, have combined their management teams located in Irvine, California and combined their wind development efforts. In this regard, EME and Edison Capital entered into a services agreement effective December 26, 2005. Under this services agreement, all existing employees of Edison Capital on the effective date of the agreement were transferred to EME, and EME provides accounting, legal, tax, management and administrative services to Edison Capital and its subsidiaries of the type previously provided by the transferred employees. Edison Capital and its subsidiaries continue to operate as independent legal entities separate and apart from EME, and EME has not assumed any obligation for the performance of any of Edison Capital's obligations to any party, whether with respect to its investment portfolio or with respect to any of the creditors of Edison Capital or its subsidiaries.

Business Strategy

EME's business strategy includes the following core elements:

- Optimizing the value of its existing generation assets through:
  - operational excellence focused on long-term cost effective maintenance;
  - integration of commercial marketing and trading activities with plant operations to enhance gross margin; and
  - effective participation in regulatory rule-making in markets where EME operates.
- Diversifying the fuel type of its generation assets through:
  - developing and acquiring new renewable energy projects, primarily wind;

- developing and acquiring natural gas-fired power projects in locations where existing or projected capacity for generation is constrained; and

- developing new clean coal generation projects such as IGCC.

- Entering into more mid- to long-term power sales contracts in order to complement its merchant sales activities.

- Reducing cash flow volatility from merchant power plants through asset-based commodity hedging activities.

- Leveraging the knowledge and expertise in trading to enhance financial performance within a disciplined risk management structure.

Description of the Industry

Electric Power Industry

The United States electric industry, including companies engaged in providing generation, transmission, distribution and ancillary services, has undergone significant deregulation, which has led to increased competition. Until the enactment of PURPA, utilities and government-owned power agencies were the only producers of bulk electric power intended for sale to third parties in the United States. PURPA encouraged the development of independent power by removing regulatory constraints relating to the production and sale of electric energy by certain non-utilities and requiring electric utilities to buy electricity from specified types of non-utility power producers, known as qualifying facilities, under specified conditions. The passage of the Energy Policy Act of 1992 further encouraged the development of independent power by significantly expanding the options available to independent power producers with respect to their regulatory status and by liberalizing transmission access. In addition, in EPAct 2005, Congress made several changes to PURPA and other statutory provisions recognizing that a significant market for electric power produced by independent power producers, such as EME, has developed in the United States and indicating that competitive wholesale electricity markets have become accepted as a fundamental aspect of the electricity industry.

As part of the regulatory developments discussed above, the FERC encouraged the formation of ISOs and RTOs. In those areas where independent system operators (ISOs) and regional transmission organizations (RTOs) have been formed, market participants have expanded access to transmission service. ISOs and RTOs may also operate real-time and day-ahead energy and ancillary service markets, which are governed by FERC-approved tariffs and market rules. The development of such organized markets into which independent power producers are able to sell has reduced their dependence on bilateral contracts with electric utilities. See further discussion of regulations under "Regulatory Matters U.S. Federal Energy Regulation."

Electric Power Markets

EME's largest power plants are its fossil fuel power plants located in Illinois, which are collectively referred to as the Illinois Plants in this prospectus, and the Homer City electric generating station located in Pennsylvania, which is referred to as the Homer City facilities in this prospectus. The Illinois Plants and the Homer City facilities sell power into PJM. PJM operates a wholesale spot energy market and determines the market-clearing price for each hour based on bids submitted by participating generators which indicate the minimum prices a bidder is willing to accept to be dispatched at various incremental generation levels. PJM conducts both day-ahead and real-time energy markets. PJM's energy markets are based on locational marginal pricing, which establishes hourly prices at specific locations throughout PJM. Locational marginal pricing is determined by considering a number of factors, including generator bids, load requirements, transmission congestion and transmission losses. PJM requires all load serving entities to maintain prescribed levels of capacity, including a reserve margin, to ensure system reliability. PJM also determines the amount of capacity available from each specific generator and operates capacity markets. PJM's capacity markets have a single market-clearing price. Load serving entities and generators, such as EME's subsidiaries Midwest Generation, with respect to the Illinois Plants, and EME Homer City, with respect to the Homer City facilities, may participate in PJM's capacity markets or transact capacity sales on a bilateral basis.

The Homer City facilities have direct, high voltage interconnections to both PJM and the NYISO, which controls the transmission grid and energy and capacity markets for New York State. As in PJM, the market-clearing price for NYISO's day-ahead and real-time energy markets is set by supplier generation bids and customer demand bids.

On April 1, 2005, the MISO commenced operation, linking portions of Illinois, Wisconsin, Indiana, Michigan, and Ohio, as well as other states in the region. In the MISO, there is a bilateral market and day-ahead and real-time markets based on locational marginal pricing similar to that of PJM. While EME does not own generating facilities within the MISO, its opening has further facilitated transparency of prices and provided additional market liquidity to support risk management and trading strategies.

For a discussion of the market risks related to the sale of electricity from these generating facilities, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Market Risk Exposures."

Competition

EME is subject to intense competition from energy marketers, utilities, industrial companies and other independent power producers. For a number of years, natural gas has been the fuel of choice for new power generation facilities for economic, operational and environmental reasons. While natural gas-fired facilities will continue to be an important part of the nation's generation portfolio, some regulated utilities are now constructing clean coal units and units powered by renewable resources, often with subsidies or under legislative mandate. These utilities generally have a lower cost of capital than most independent power producers 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.

Where EME sells power from plants from which the output is not committed to be sold under long-term contracts, commonly referred to as merchant plants, EME is subject to market fluctuations in prices based on a number of factors, including the amount of capacity available to meet demand, the price and availability of fuel and the presence of transmission constraints. Some of EME's competitors, such as electric utilities and distribution companies, have their own generation capacity, including nuclear generation. These companies, generally larger than EME, have a lower cost of capital and may have competitive advantages as a result of their scale and location of their generation facilities.

Operating Segments

EME operates in one line of business, independent power production, with all its continuing operations located in the United States, except the Doga project in Turkey. Operating revenues are primarily related to the sale of power generated from the Illinois Plants and the Homer City facilities.

EME is headquartered in Irvine, California with additional offices located in Chicago, Illinois and Boston, Massachusetts.

Overview of Facilities

As of June 30, 2007, our operations consisted of ownership or leasehold interests in the following operating power plants:

Power Plants	Location	Primary Electric Purchaser(2)	Fuel Type	Ownership Interest	Net Physical Capacity (in MW)	EME's Capacity Pro Rata Share (in MW)	Number of Plants
Merchant Power Plants							
Illinois Plants(1)	Illinois	PJM	Coal/Oil/Gas	100%	5,918	5,918	6
Homer City(1)	Pennsylvania	PJM	Coal	100%	1,884	1,884	1
Contracted Power Plants							
Domestic							
Big 4 Projects							
Kern River(1)	California	SCE	Natural Gas	50%	300	150	1
Midway-Sunset(1)	California	SCE	Natural Gas	50%	225	113	1
Sycamore(1)	California	SCE	Natural Gas	50%	300	150	1
Watson	California	SCE	Natural Gas	49%	385	189	1
Westside Projects							
Coalinga(1)	California	PG&E	Natural Gas	50%	38	19	1
Mid-Set(1)	California	PG&E	Natural Gas	50%	38	19	1
Salinas River(1)	California	PG&E	Natural Gas	50%	38	19	1
Sargent Canyon(1)	California	PG&E	Natural Gas	50%	38	19	1
American Bituminous(1)	West Virginia	MPC	Waste Coal	50%	80	40	1
March Point	Washington	PSE	Natural Gas	50%	140	70	1
Sunrise(1)	California	CDWR	Natural Gas	50%	572	286	1
Huntington	New York	LIPA	Biomass	38%	25	9	1
San Juan Mesa(1)	New Mexico	SPS	Wind	75%	120	90	1
Minnesota Wind Projects	Minnesota	NSPC/IPLC	Wind	75-99%	83	75	7
Iowa Wind Projects							
Storm Lake	Iowa	MEC	Wind	100%	109	109	1
Crosswinds	Iowa	CBPC	Wind	99%	21	21	1
Hardin	Iowa	IPLC	Wind	99%	15	15	1
Wildorado	Texas	SPS	Wind	99.9%	161	161	1
International							
Doga(1)	Turkey	TEDAS	Natural Gas	80%	180	144	1
Total					10,670	9,500	32

(1) Plant is operated under contract by an operations and maintenance subsidiary of ours (partially owned plants) or plant is operated directly by a subsidiary of ours (wholly owned plants).

(2) Electric purchaser abbreviations are as follows:

PJM	PJM Interconnection, LLC	SPS	Southwestern Public Service
SCE	Southern California Edison Company	NSPC	Northern States Power Company
PG&E	Pacific Gas & Electric Company	IPLC	Interstate Power and Light Company
MPC	Monongahela Power Company	MEC	Mid-American Energy Company

PSE	Puget Sound Energy, Inc.	CBPC	Corn Belt Power Cooperative
CDWR	California Department of Water Resources	TEDAS	Türkiye Elektrik Dagitim Anonim Sirketi
LIPA	Long Island Power Authority		

A description of EME's larger power plants and major investments in energy projects is set forth below. In addition to the facilities and power plants that EME owns, EME uses the term "its" in regard to facilities and power plants that EME or an EME subsidiary operates under sale-leaseback arrangements.

Illinois Plants

On December 15, 1999, Midwest Generation completed a transaction with Commonwealth Edison, now a subsidiary of Exelon Corporation, to acquire the Illinois Plants. The Illinois Plants are located in the Mid-America Interconnected Network, which has transmission connections to the East Central Area Reliability Council and other regional markets.

The Illinois Plants include the following:

Operating Plant or Site	Location	Leased/ Owned	Fuel	Megawatts
Electric Generating Facilities				
Crawford Station	Chicago, Illinois	owned	coal	542
Fisk Station	Chicago, Illinois	owned	coal	326
Joliet Unit 6	Joliet, Illinois	owned	coal	290
Joliet Units 7 and 8	Joliet, Illinois	leased	coal	1,044
Powerton Station	Pekin, Illinois	leased	coal	1,538
Waukegan Station	Waukegan, Illinois	owned	coal	781(1)
Will County Station	Romeoville, Illinois	owned	coal	1,092(2)
Peaking Units				
Fisk	Chicago, Illinois	owned	oil/gas	197
Waukegan	Waukegan, Illinois	owned	oil/gas	108
Total				5,918
Other Plant or Site				
Collins Station(3)	Grundy County, Illinois			
Crawford peaker(4)	Chicago, Illinois			
Joliet peaker(5)	Joliet, Illinois			
Calumet peaker(5)	Chicago, Illinois			
Electric Junction peaker(5)	Aurora, Illinois			
Lombard peaker(5)	Lombard, Illinois			
Sabrooke peaker(5)	Rockford, Illinois			

(1) The Waukegan Station is comprised of Units 6, 7 and 8. Midwest Generation has agreed with the Illinois EPA to shut down permanently Waukegan Station Unit 6 (100 MW) on or before December 31, 2007. For further discussion, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Environmental Matters and Regulations Air Quality Regulation Clean Air Act Illinois."

(2) The Will County Station is comprised of Units 1, 2, 3, and 4. Operations at Will County Station Units 1 and 2 (totaling 310 MW) were returned to service in late 2004 after being suspended in January 2003. Midwest Generation has agreed with the Illinois EPA to shut down permanently Will County Station Units 1 and 2 on or before December 31, 2010. For further discussion, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Environmental Matters and Regulations Air Quality Regulation Clean Air Act Illinois."

(3) All Collins Station units ceased operations and were decommissioned on or before December 31, 2004.

(4) Peaking units ceased operations as of April 21, 2005.

(5) Peaking units ceased operations as of December 31, 2004.

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As part of the purchase of the Illinois Plants, EME assigned its right to purchase the Collins Station to third-party entities and Midwest Generation simultaneously entered into a long-term lease arrangement of the Collins Station with these third-party entities. In April 2004, Midwest Generation terminated the Collins Station lease through a negotiated transaction with the lease equity investor and received title to the Collins Station as part of the transaction. Following the lease termination, Midwest Generation permanently ceased operations at the Collins Station, effective September 30, 2004, and decommissioned the plant prior to December 31, 2004, by which time all units were permanently retired from service, disconnected from the grid, and rendered inoperable, with all operating permits surrendered.

In August 2000, EME completed sale-leaseback transactions involving its Powerton and Units 7 and 8 of its Joliet power facilities. EME sold these assets to third parties to obtain capital to repay corporate debt and entered into long-term leases of the facilities from these third parties to maintain control of the use of the power plants during the terms of the leases. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Transactions."

Illinois Power Sales

Energy generated at the Illinois Plants was historically sold under three power purchase agreements between Midwest Generation and Exelon Generation under which Exelon Generation was obligated to make capacity payments for the plants under contract and energy payments for the energy produced by the Illinois Plants and taken by Exelon Generation. The power purchase agreements began on December 15, 1999, and all were terminated by December 31, 2004.

All the energy and capacity from the Illinois Plants is now sold under terms, including price and quantity, arranged by EMMT, an EME subsidiary engaged in the power marketing and trading business, with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. Thus, EME is subject to market risks related to the price of energy and capacity from the Illinois Plants. Power generated at the Illinois Plants is generally sold into the PJM market.

For a discussion of the risks related to Midwest Generation's sale of electricity, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Market Risk Exposures."

Transmission

Prior to May 1, 2004, sales of power produced by Midwest Generation required using transmission that had to be obtained from Commonwealth Edison. As discussed previously, the Illinois Plants are now dispatched into the PJM market. Sales may also be made from PJM into the MISO, where there is a single rate for transmission.

On November 18, 2004, the FERC issued an order eliminating regional through and out transmission rates in the region encompassed by PJM and the MISO. The effect of this order was to eliminate so-called rate pancaking between PJM and the MISO on a prospective basis. Rate pancaking occurs when energy must move through multiple, separately priced transmission systems to travel from its point of production to its point of delivery, and each transmission owner along the line charges separately for the use of its system. At the same time, the FERC also imposed a transitional revenue recovery mechanism which has created controversy and some continuing uncertainty as to its impact on transactions in the region. The mechanism required the filing of tariffs by PJM and the MISO imposing a Scams Elimination Cost Adjustment, or SECA, to be in effect until May 1, 2006, to compensate the "new PJM companies" AEP, Commonwealth Edison and Dayton Power & Light, among others for lost revenues attributable to the elimination of such rates. On November 30, 2004, the FERC clarified that SECAs can be recovered for lost revenues associated with elimination of intra-RTO pancaked rates.

The response to the November 18 and November 30 orders from the parties potentially liable for the SECAs was strongly negative. Rehearings were sought by a broad range of interests that are opposed to the imposition of SECAs. Although both PJM and the MISO have made tariff filings with the FERC that purport to comply with the orders and eliminate through and out transmission rates as of December 1, 2004, numerous protests to such filings have been made, challenging SECAs on legal and equitable grounds and evidentiary hearings have been held by the FERC. Pending further orders of the FERC and/or the outcome of future hearings, under the provisions of the PJM tariff as filed, Midwest Generation is currently not subject to SECAs with respect to its sales of power within PJM. It is not possible, however, to predict the outcome of the FERC proceedings or to rule out the possibility that Midwest Generation could be ordered in the future to pay SECAs with respect to sales within PJM after December 1, 2004.

For further discussion of the market risks related to Midwest Generation's transmission service, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Market Risk Exposures."

Fuel Supply

Coal is used to fuel 5,613 MW of Midwest Generation's generating capacity. The coal is purchased from several suppliers that operate mines in the Southern PRB of Wyoming. The total volume of coal consumed annually is largely dependent on the amount of generation and ranges between 16 million to 20 million tons.

All coal is transported under long-term transportation agreements with the Union Pacific Railroad and various delivering carriers. As of December 31, 2006, Midwest Generation leased approximately 4,200 railcars to transport the coal from the mines to the generating stations and the leases have remaining terms that range from less than one year to 13 years, with options to extend the leases or purchase some railcars at the end of the lease terms. The coal is transported nearly 1,200 miles from the mines to the Illinois Plants.

Coal for the Fisk and Crawford Stations is first shipped by rail to the Will County Station where it is transferred from the railcars, blended as necessary to meet station specifications, and loaded into river barges. These barges are towed to the stations by an independent contractor under a transportation agreement with Midwest Generation.

Midwest Generation has approximately 305 MW of peaking capacity in the form of simple cycle combustion turbines at the Fisk and Waukegan Stations. These units are fueled with distillate fuel oils.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Contractual Obligations, Commitments and Contingencies," for additional discussion of contractual commitments related to Midwest Generation's fuel supply and coal transportation contracts.

Homer City Facilities

On March 18, 1999, EME Homer City completed a transaction with GPU, Inc., New York State Electric & Gas Corporation and their respective affiliates to acquire the Homer City facilities. These facilities consist of three coal-fired boilers and steam turbine-generator units (referred to as Units 1, 2 and 3), one coal cleaning facility, water supply provided by a reservoir known as Two Lick Dam and associated support facilities in the mid-Atlantic region of the United States.

On December 7, 2001, EME Homer City completed a sale-leaseback of the Homer City facilities to third-party lessors. EME Homer City sold the Homer City facilities to obtain capital to repay corporate debt and entered into long-term leases to continue to operate the Homer City facilities during the terms of the leases. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Off-Balance Sheet Transactions."

Fuel Supply

Units 1 and 2 typically consume approximately 3.3 million to 3.5 million tons of mid-range sulfur coal per year. Approximately 90% or more of this coal is obtained under contracts with the remainder purchased in the spot market as needed. Two types of coal are purchased, ready to burn coal and raw coal. Ready to burn coal is of a quality that can be burned directly in Units 1 and 2, whereas the raw coal purchased for consumption by Units 1 and 2 must be cleaned in the Homer City coal cleaning facility, which has the capacity to clean up to 5 million tons of coal per year.

Unit 3 consumes approximately 2 million tons of coal per year. EME Homer City purchases the majority of its Unit 3 coal under contracts with the balance purchased in the spot market. A wet scrubber flue gas desulfurization system for Unit 3 enables this unit to burn less expensive, higher sulfur coal, while still meeting environmental standards for emission control.

In general, the coal purchased for all three units originates from mines that are within approximately 100 miles of the Homer City facilities. It is delivered to the station by truck and by rail.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Contractual Obligations, Commitments and Contingencies," for additional discussion of contractual commitments related to EME Homer City's fuel supply and coal transportation contracts.

Emission Allowances for the Homer City Facilities and Illinois Plants

Certain state and federal environmental laws require power plant operators to hold or obtain emission allowances equal, on an annual basis, to their plants' emissions of SO2 and, on a seasonal basis, to their plants' emissions of NOx. Emission allowances were acquired as part of the acquisition of the Homer City facilities and the Illinois Plants. Additional allowances are purchased by EME Homer City and Midwest Generation when operations make this necessary and are sold when they have more than needed for planned levels of operation.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Environmental Matters and Regulations" for a discussion of environmental regulations related to emissions. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Market Risk Exposures Commodity Price Risk Emission Allowances Price Risk" for a discussion of price risks related to the purchase or sale of emission allowances.

Big 4 Projects

EME owns partnership investments in Kern River Cogeneration Company, Midway-Sunset Cogeneration Company, Sycamore Cogeneration Company and Watson Cogeneration Company, as described below. These projects sell power to SCE, an affiliate of EME. Because these projects have similar economic characteristics and have been used, collectively, to obtain financing by Edison Mission Energy Funding Corp., a special purpose entity, EME views these projects collectively and refers to them as the Big 4 projects. See "Audited Consolidated Financial Statements of Edison Mission Energy Notes to Consolidated Financial Statements Note 1. Summary of Significant Accounting Policies," for discussion of EME's accounting for this entity.

Kern River Cogeneration Plant

EME owns a 50% partnership interest in Kern River Cogeneration Company, which owns a 300 MW natural gas-fired cogeneration facility located near Bakersfield, California, which EME refers to as the Kern River project. Kern River Cogeneration's prior long-term power purchase agreement with SCE and its steam supply agreement with Texaco Exploration and Production Inc., a wholly owned subsidiary of Chevron Corporation, both expired on August 9, 2005. On August 10, 2005, Kern River Cogeneration entered into a Reformed Standard Offer No. 1 As-Available Energy and Capacity Power Purchase Agreement with SCE, which was in effect until June 1, 2006 when it was replaced by a new five-year bilateral agreement with SCE. On August 10, 2005, Kern River Cogeneration also entered into a new Steam Purchase and Sale Agreement with Chevron North America Exploration and Production Company, a division of Chevron U.S.A., Inc., with a term equivalent to the new power purchase agreement.

Midway-Sunset Cogeneration Plant

EME owns a 50% partnership interest in Midway-Sunset Cogeneration Company, which owns a 225 MW natural gas-fired cogeneration facility located near Taft, California, which EME refers to as the Midway-Sunset project. Midway-Sunset Cogeneration sells electricity to SCE, Aera Energy LLC and PG&E under power purchase agreements that expire in 2009 and steam to Aera Energy LLC under a steam supply agreement that also expires in 2009.

Sycamore Cogeneration Plant

EME owns a 50% partnership interest in Sycamore Cogeneration Company, which owns and operates a 300 MW natural gas-fired cogeneration facility located near Bakersfield, California, which EME refers to as the Sycamore project. Sycamore Cogeneration sells electricity to SCE under a power purchase agreement that expires on December 31, 2007 and steam to Chevron North America Exploration and Production Company under a steam supply agreement that also expires on December 31, 2007.

Watson Cogeneration Plant

EME owns a 49% partnership interest in Watson Cogeneration Company, which owns a 385 MW natural gas-fired cogeneration facility located in Carson, California, which EME refers to as the Watson project. Watson Cogeneration sells electricity to SCE and to BP West Coast Products LLC under power purchase agreements that expire in 2008 and steam to BP West Coast Products LLC under a steam supply agreement that also expires in 2008.

Other Power Plants

Westside Power Plants

EME owns partnership investments in Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Salinas River Cogeneration Company, and Sargent Canyon Cogeneration Company. Due to similar economic characteristics, EME views these projects collectively and refers to them as the Westside projects. EME owns a 50% partnership interest in each of the companies listed above and each company owns a 38 MW natural gas-fired cogeneration facility located in California. Three of these projects sold electricity to PG&E under 15-year power purchase agreements which expired during the first quarter of 2007. These projects executed agreements with PG&E for the continued sale of electricity at "as available" rates. Mid-Set Cogeneration's original power purchase agreement with PG&E expired in May 2004. Mid-Set Cogeneration continues to sell electricity to PG&E at "as available" rates under an agreement that expires on December 31, 2009.

American Bituminous Power Plant

EME owns a 50% interest in American Bituminous Power Partners, L.P., which owns an 80 MW waste coal facility located in Grant Town, West Virginia, which EME refers to as the Ambit project. Ambit sells electricity to Monongahela Power Company under a power purchase agreement that expires in 2035.

March Point Cogeneration Plant

EME owns a 50% partnership interest in March Point Cogeneration Company, which owns a 140 MW natural gas-fired cogeneration facility located in Anacortes, Washington, which EME refers to as the March Point project. The March Point project consists of two phases. Phase 1 is an 80 MW gas turbine cogeneration facility and Phase 2 is a 60 MW gas turbine combined cycle facility. March Point Cogeneration sells electricity to Puget Sound Energy, Inc. under a power purchase agreement that expires in 2011 and steam to Equilon Enterprises, LLC under a steam supply agreement that also expires in 2011. During the third quarter of 2005, EME recorded a $55 million charge to impair fully its equity investment in the March Point project due to the adverse impact on cash flows from increases in long-term natural gas prices. For further discussion, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Annual Results of Continuing Operations for 2006, 2005 and 2004 Earnings from Unconsolidated Affiliates."

Sunrise Power Plant

EME owns a 50% interest in Sunrise Power Company, LLC, which owns a 572 MW natural gas-fired facility in Kern County, California, which EME refers to as the Sunrise project. Sunrise Power entered into a long-term power purchase agreement with the California Department of Water Resources in June 2001, which expires in 2012.

Huntington Biomass Project

EME owns a 38% limited partnership interest in Covanta Huntington LP, which owns a 25 MW waste-to-energy facility located near the Town of Huntington, New York, which EME refers to as the Huntington project. The project processes waste materials under a solid waste disposal services agreement with the Town of Huntington, which is set to expire in 2012 with an option to renew. The project also sells electricity to Long Island Power Authority under a power purchase agreement that expires in 2012.

San Juan Mesa Wind Power Plant

EME owns a 75% interest in San Juan Mesa Wind Project LLC, which owns a 120 MW wind ranch located near Elida, New Mexico, which EME refers to as the San Juan Mesa wind project. The project sells electricity to Southwestern Public Service, a subsidiary of Xcel Energy, under a power purchase agreement that expires in 2025. The San Juan Mesa wind project achieved commercial operation in December 2005.

Minnesota Wind Projects

EME owns interests of between 75% and 99% in 37 separate Minnesota limited liability companies, each of which owns a small wind-powered electric generation facility in Murray, Cottonwood, Lincoln and Pipestone counties in Minnesota, which EME refers to collectively as the Minnesota wind projects. The Minnesota wind projects collectively total approximately 83 MW. Each of the Minnesota wind projects sells electricity to either (i) Northern States Power Company under a power purchase agreement that expires between 2025 and 2034 or (ii) Interstate Power and Light Company under a power purchase agreement that expires in 2021.

Storm Lake Wind Power Plant

EME owns a 100% interest in Storm Lake Power Partners I LLC, which owns a 109 MW wind ranch located near Alta, Iowa, which EME refers to as the Storm Lake wind project. The project sells electricity to Mid-American Energy Company under a power purchase agreement that expires in 2020.

Crosswinds Wind Project

EME owns a 99% interest in Crosswinds Energy Projects consisting of 10 separate limited liability companies, which collectively own a 21 MW wind farm located in northwestern Iowa, which EME refers to as the Crosswinds wind project. The project sells electricity to Corn Belt Power Cooperative under a 20-year power purchase agreement. The Crosswinds wind project achieved commercial operation in June 2007.

Hardin Wind Project

EME owns a 99% interest in Hardin Hilltop Projects consisting of seven separate limited liability companies, which collectively own a 15 MW wind farm located in western Iowa, which EME refers to as the Hardin wind project. The project sells electricity to Interstate Power and Light Company under a 20-year power purchase agreement. The Hardin wind project achieved commercial operation in May 2007.

Wildorado Wind Power Plant

EME owns a 99.9% interest in Wildorado Wind, L.P., which owns a 161 MW wind farm located in the panhandle of northern Texas, which EME refers to as the Wildorado wind project. The project sells electricity to Southwestern Public Service Company under a 20-year power purchase agreement. The Wildorado wind project achieved commercial operation in April 2007.

Doga Cogeneration Plant

EME owns an 80% interest in Doga Enerji, which owns a 180 MW natural gas-fired cogeneration plant near Istanbul, Turkey, which EME refers to as the Doga project. Doga Enerji sells electricity to

Türkiye Elektrik Dagitim Anonim Sirketi, commonly known as TEDAS, under a power purchase agreement that expires in 2019.

Overview of Projects under Construction

As of June 30, 2007, EME had the projects described below under construction. Each project will, after its completion, use wind to generate electricity from turbines, which will be sold pursuant to the project's power purchase agreement.

Sleeping Bear Wind Power Plant

EME owns a 100% interest in Sleeping Bear LLC, which owns a 95 MW wind farm located in northwestern Oklahoma, which EME refers to as the Sleeping Bear wind project. This project started construction in October 2006 and is scheduled for completion during the third quarter of 2007. The project will sell electricity to Public Service Company of Oklahoma, a unit of American Electric Power, under a 25-year power purchase agreement.

Jeffers Wind Power Plant

EME owns a 99.9% interest in Jeffers Wind 20 LLC, which owns a 50 MW wind farm located in western Minnesota, which EME refers to as the Jeffers wind project. This project started construction in October 2006 and is scheduled for completion during the third quarter of 2007. The project will sell electricity to Northern States Power Company under Minnesota's Community-Based Energy Development Program under a 20-year power purchase agreement.

Mountain Wind I Power Plant

EME owns a 100% interest in Mountain Wind Power LLC, which owns a 61 MW wind farm located in Wyoming, which EME refers to as the Mountain Wind I project. This project started construction in May 2007 and is scheduled for completion during the first quarter of 2008. The project will sell electricity to PacifiCorp under a 20-year power purchase agreement.

Forward Wind Power Plant

EME owns a 100% interest in Forward Windpower LLC, which owns a 29 MW wind farm located in Pennsylvania, which EME refers to as the Forward wind project. This project started construction in June 2007 and is scheduled for completion during the first quarter of 2008. The project will sell electricity to Constellation New Energy under a 10-year power purchase agreement.

Lookout Wind Power Plant

EME owns a 100% interest in Lookout Windpower LLC, which owns a 38 MW wind farm located in Pennsylvania, which EME refers to as the Lookout wind project. This project started construction in June 2007 and is scheduled for completion during the first quarter of 2008. The project will sell electricity into PJM as a merchant wind generator.

Odin Wind Power Plant

EME owns a 99.9% interest in Odin Wind Farm, LLC, which owns a 20 MW wind farm located in Minnesota, which EME refers to as the Odin wind project. This project started construction in

May 2007 and is scheduled for completion during the first quarter of 2008. The project will sell electricity to Missouri River Energy Services under a 20-year power purchase agreement.

Business Development

Wind Projects

EME expects to make significant investments in wind projects during the next several years. Historically, wind projects have received federal subsidies in the form of production tax credits. In August 2005, production tax credits were made available for new wind projects placed in service by December 31, 2007 under EPAct 2005. In December 2006, the deadline for production tax credits was extended for one year to apply to new wind projects placed in service by December 31, 2008.

In seeking to find and invest in new wind projects, EME has teamed with third-party development companies through joint development agreements that provide for funding of development costs through loans and joint decision-making on key contractual agreements (e.g., power purchase contracts, site agreements and permits). Joint development agreements and development loans may be for a specific project or a group of identified and future projects and generally grant EME the exclusive right to acquire related projects. As of June 30, 2007, EME had a development pipeline of potential wind projects with an installed capacity of approximately 3,100 MW (development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive negotiation rights). See "Management's Discussion and Analysis of Financial Condition and Results of Operations Management's Overview Management's Overview Business Development" for further discussion.

In general, EME funds development costs under joint development agreements through loans (referred to as development loans) which are secured by project specific assets. A project's development loans are repaid upon the completion of the project. If the project is purchased by EME, repayment is made from proceeds received from EME in connection with the purchase. In the event EME declines to purchase a project, repayment is made from proceeds received from the sale of the project to third parties or from other sources as available.

In addition to joint development agreements, EME may purchase wind projects from third-party developers in various stages of development, construction or operation. In order to support investment in wind projects, EME has negotiated turbine supply agreements in advance of specific project requirements. As of June 30, 2007, EME has purchased turbines for future wind projects totaling 1,414 MW. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Contractual Obligations, Commitments and Contingencies Contractual Obligations Interim Update at June 30, 2007 Turbine Commitments" and " Contractual Obligation at December 31, 2006 Purchase Obligations Turbine Commitments" for further discussion.

Thermal Projects

EME expects to make investments in thermal projects during the next several years. As part of its development efforts, EME is in the process of obtaining permits for two sites in Southern California for peaker plants. EME is also a participant in potential gasification projects using coal or other fuels. These projects are generally large and complex, requiring significant development, engineering and construction efforts over a number of years to complete. Development efforts include feasibility studies, site development and acquisition, permitting, and contractual arrangements, including fuel supply and interconnection. In addition, EME may participate in Federal or state programs designed to encourage development of new gasification projects. Generally, it is expected that thermal projects in which EME invests will sell electricity under long-term power purchase contracts. EME actively participates in bids to utilities in response to requests for proposals to build new generation and may acquire existing generation in selected markets.

Hedging and Trading Activities

EME's power marketing and trading subsidiary, EMMT, markets the energy and capacity of EME's merchant generating fleet and, in addition, trades electric power and energy and related commodity and financial products, including forwards, futures, options and swaps. EMMT segregates its marketing and trading activities into two categories:

Hedging EMMT engages in the sale and hedging of electricity and purchase of fuels (other than coal) through intercompany contracts with EME's subsidiaries that own or lease the Illinois Plants and the Homer City facilities. The objective of these activities is to sell the output of the power plants on a forward basis or to hedge the risk of future change in the price of electricity, thereby increasing the predictability of earnings and cash flows. EMMT also conducts hedging associated with the purchase of fuels, including natural gas and fuel oil. Transactions entered into related to hedging activities are designated separately from EMMT's trading activities and are recorded in what EMMT calls its hedge book. Not all of the contracts entered into by EMMT for hedging activities qualify for hedge accounting under SFAS No. 133. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Market Risk Exposures Accounting for Energy Contracts" for a discussion of accounting for derivative contracts.

Trading As part of its trading activities, EMMT seeks to generate profit from the volatility of the price of electricity, fuels and transmission by buying and selling contracts for their sale or provision, as the case may be, in wholesale markets under limitations approved by EME's risk management committee. EMMT records these transactions in what it calls its proprietary book.

In conducting EME's hedging and trading activities, EMMT contracts with a number of utilities, energy companies and financial institutions. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with reselling the contracted product to another buyer at a lower price or having to purchase the contracted product from another supplier at a higher price if the non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time such counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by its counterparties. Credit risk is measured by the loss EME would record if its counterparties failed to perform pursuant to the terms of their contractual obligations. EME has established controls to determine and monitor the creditworthiness of counterparties and uses master netting agreements whenever possible to mitigate its exposure to counterparty risk. EME requires counterparties to pledge collateral when deemed necessary. EME uses published credit ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. The credit quality of EME's counterparties is reviewed regularly by EME's risk management committee. In addition to continuously monitoring its credit exposure to its counterparties, EME also takes appropriate steps to limit or lower credit exposure. Despite this, there can be no assurance that EME's actions to mitigate risk will be wholly successful or that collateral pledged will be adequate.

EME's merchant power plants and energy trading activities expose EME to commodity price risks. Commodity price risks are actively monitored by EME's risk management committee to ensure compliance with EME's risk management policies. Policies are in place which define risk tolerances, and procedures exist which allow for monitoring of all commitments and positions with regular reviews by the risk management committee. EME uses "value at risk" to identify, measure, monitor and control its overall market risk exposure in respect of its Illinois Plants, its Homer City facilities and its proprietary positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify risk factors. Value at risk measures the possible loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and reliance on a single risk measurement tool, EME supplements this approach with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss limits and counterparty credit exposure limits. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

In executing agreements with counterparties to conduct hedging or trading activities, EME generally provides credit support when necessary through margining arrangements (agreements to provide or receive collateral, letters of credit or guarantees based on changes in the market price of the underlying contract under specific terms). To manage its liquidity, EME assesses the potential impact of future price changes in determining the amount of collateral requirements under existing or anticipated forward contracts. There is no assurance that EME's liquidity will be adequate to meet margin calls from counterparties in the case of extreme market changes or that the failure to meet such cash requirements would not have a material adverse effect on its liquidity. See "Risk Factors."

Significant Customers

Beginning in January 2007, EME derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Illinois Plants to Commonwealth Edison under load requirements services contracts. Sales under these contracts accounted for 19% of EME's consolidated operating revenues during the six months ended June 30, 2007. In the past three fiscal years and the six months ended June 30, 2007, EME also derived a significant source of its operating revenues from electric power sold into the PJM market from the Homer City facilities and the Illinois Plants. Sales into PJM accounted for approximately 58%, 69% and 23% of EME's consolidated operating revenues for the years ended December 31, 2006, 2005 and 2004, respectively, and 49% for the six months ended June 30, 2007. For the year ended December 31, 2004, approximately 15% of EME's consolidated operating revenues generated at the Homer City facilities and Illinois Plants was from sales to BP Energy Company, a third-party customer. In 2004, EME also derived a significant source of its revenues from the sale of energy and capacity generated at the Illinois Plants to Exelon Generation primarily under three power purchase agreements. These power purchase agreements had all expired by the end of 2004. Exelon Generation accounted for approximately 35% of EME's consolidated operating revenues for the year ended December 31, 2004.

Insurance

EME maintains insurance policies consistent with those normally carried by companies engaged in similar business and owning similar properties. EME's insurance program includes all-risk property insurance, including business interruption, covering real and personal property, including losses from boilers, machinery breakdowns, and the perils of earthquake and flood, subject to specific sublimits. EME also carries general liability insurance covering liabilities to third parties for bodily injury or property damage resulting from operations, automobile liability insurance and excess liability insurance. Limits and deductibles in respect of these insurance policies are comparable to those carried by other electric generating facilities of similar size. However, no assurance can be given that EME's insurance will be adequate to cover all losses.

The Homer City property insurance program currently covers losses up to $1.1 billion. Under the terms of the participation agreements entered into on December 7, 2001 as part of the sale-leaseback transaction of the Homer City facilities, EME Homer City is required to maintain specified minimum insurance coverages if and to the extent that such insurance is available on a commercially reasonable basis. Although the insurance covering the Homer City facilities is comparable to insurance coverages normally carried by companies engaged in similar businesses, and owning similar properties, the insurance coverages that are in place do not meet the minimum insurance coverages required under the participation agreements. Due to the current market environment, the minimum insurance coverage is not commercially available at reasonable prices. EME Homer City has obtained a waiver under the participation agreements which permits it to maintain its current insurance coverage through June 1, 2008.

Seasonality

Due to higher electric demand resulting from warmer weather during the summer months and cold weather during the winter months, electric revenues from the Illinois Plants and the Homer City facilities vary substantially on a seasonal basis. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall) further reducing generation and increasing major maintenance costs which are recorded as an expense when incurred. Accordingly, earnings from the Illinois Plants and the Homer City facilities are seasonal and have significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Market Risk Exposures Commodity Price Risk Energy Price Risk Affecting Sales from the Illinois Plants" and " Energy Price Risk Affecting Sales from the Homer City Facilities" for further discussion regarding market prices.

EME's third quarter equity in income from its energy projects is materially higher than equity in income related to other quarters of the year due to warmer weather during the summer months and because a number of EME's energy projects located on the West Coast have power sales contracts that provide for higher payments during the summer months.

Discontinued Operations

During 2004 and early 2005, EME sold assets totaling 6,452 MW, which constituted most of its international assets. Except for the Doga project, which was not sold, these international assets are accounted for as discontinued operations in accordance with SFAS No. 144 and, accordingly, all prior periods have been restated to reclassify the results of operations and assets and liabilities as discontinued operations. The sale of the international operations included:

- On September 30, 2004, EME sold its 51.2% interest in Contact Energy Limited to Origin Energy New Zealand Limited.
- On December 16, 2004, EME sold the stock and related assets of MEC International B.V. to IPM. The sale of MEC International included the sale of EME's ownership interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico.
- On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) hydroelectric power project located in the Philippines to CBK Projects B.V.
- On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project to IPM.

See "Audited Consolidated Financial Statements of Edison Mission Energy Notes to Consolidated Financial Statements Note 5. Divestitures" for further details of discontinued operations.

Regulatory Matters

General

EME's operations are subject to extensive regulation by governmental agencies. EME's operating projects are subject to energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the ownership and operation of its projects, and the use of electric energy, capacity and related products, including ancillary services from its projects. Federal laws and regulations govern, among other things, transactions by and with purchasers of power, including utility companies, the operation of a power plant and the ownership of a power plant. Under limited circumstances where exclusive federal jurisdiction is not applicable or specific exemptions or waivers from state or federal laws or regulations are otherwise unavailable, federal and/or state utility regulatory commissions may have broad jurisdiction over non-utility owned electric power plants. Energy-producing projects are also subject to federal, state and local laws and regulations that govern the geographical location, zoning, land use and operation of a project. Federal, state and local environmental requirements generally require that a wide variety of permits and other approvals be obtained before the commencement of construction or operation of an energy-producing facility and that the facility then operate in compliance with these permits and approvals.

EME is subject to a varied and complex body of laws and regulations that are in a state of flux. Intricate and changing environmental and other regulatory requirements could necessitate substantial expenditures and could create a significant risk of expensive delays or significant loss of value in a project if it were to become unable to function as planned due to changing requirements or local opposition.

U.S. Federal Energy Regulation

The FERC has ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy (other than transmission that is "bundled" with retail sales) under the Federal Power Act and with respect to certain interstate sales, transportation and storage of natural gas under the Natural Gas Act of 1938. Prior to February 8, 2006, the Securities and Exchange Commission had regulatory powers with respect to upstream owners of electric and natural gas utilities under the Public Utility Holding Company Act of 1935, as amended (PUHCA 1935), which was repealed as of that date by EPAct 2005. The enactment of PURPA and the adoption of regulations under PURPA by the FERC provided incentives for the development of cogeneration facilities and small power production facilities using alternative or renewable fuels by establishing certain exemptions from the Federal Power Act and PUHCA 1935 for the owners of qualifying facilities. The passage of the Energy Policy Act in 1992 further encouraged independent power production by providing additional exemptions from PUHCA 1935 for exempt wholesale generators (EWGs) and foreign utility companies.

The Energy Policy Act of 2005

A comprehensive energy bill was passed by the U.S. House and Senate in July 2005 and was signed by President Bush on August 8, 2005. Known as "EPAct 2005," this comprehensive legislation includes provisions for the repeal of PUHCA 1935 and amendments to PURPA, for merger review reform, for the introduction of new regulations regarding "Transmission Operation Improvements," for FERC authority to impose civil penalties for violation of its regulations, for transmission rate reform, for incentives for various generation technologies and for the extension through December 31, 2007 of production tax credits for wind and other specified types of generation.

The FERC has finalized rules to implement the congressionally mandated repeal of PUHCA 1935, effective February 8, 2006, and enactment of the Public Utility Holding Company Act of 2005 (PUHCA 2005). The repeal of PUHCA 1935 and its replacement by PUHCA 2005 effectively eliminates many of the restrictions on outside investment in the electricity industry, investment by and transactions between utilities, and geographic constraints on utility systems. PUHCA 1935 repeal is expected to enable investment in utility systems by private equity funds, financial institutions, foreign utility companies, and other non-utility companies without the burden of registration as a "public utility holding company." It also eliminates limits on investment in non-utility operations companies that were registered holding companies under PUHCA 1935, subject to other applicable regulatory limitations, as well as geographic limits on potential utility combinations. PUHCA 2005 is primarily a "books and records access" statute and does not give the FERC any new substantive authority under the Federal Power Act or Natural Gas Act. The FERC has also issued final rules to implement the electric company merger and acquisition provisions of EPAct 2005.

On July 20, 2006, the FERC certified the North American Electric Reliability Council (NERC) as its Electric Reliability Organization to establish and enforce reliability standards for the bulk power system. On March 16, 2007, the FERC issued a final rule approving 83 reliability standards proposed by the NERC. The final rule became effective, and compliance with these standards became mandatory, on June 18, 2007. EME believes it has taken all steps to be compliant with current NERC reliability standards that apply to generators. EME anticipates that the FERC will adopt more stringent reliability standards in the future. The financial impact of complying with future standards cannot be determined at this time.

Federal Power Act

The Federal Power Act grants the FERC exclusive jurisdiction over the rates, terms and conditions of wholesale sales of electricity and transmission services in interstate commerce (other than transmission that is "bundled" with retail sales), including ongoing, as well as initial, rate jurisdiction. This jurisdiction allows the FERC to revoke or modify previously approved rates after notice and opportunity for hearing. These rates may be based on a cost-of-service approach or, in geographic and product markets determined by the FERC to be workably competitive, may be market based. Most qualifying facilities, as that term is defined in PURPA, are exempt from the ratemaking and several other provisions of the Federal Power Act. EWGs certified in accordance with the FERC's rules under PUHCA 2005 and other non-qualifying facility independent power projects are subject to the Federal Power Act and to the FERC's ratemaking jurisdiction thereunder, but the FERC typically grants EWGs the authority to charge market-based rates to purchasers which are not affiliated electric utility companies as long as the absence of market power is shown. In addition, the Federal Power Act grants the FERC jurisdiction over the sale or transfer of jurisdictional facilities, including wholesale power sales contracts and, after EPAct 2005, generation facilities, and in some cases, jurisdiction over the issuance of securities or the assumption of specified liabilities and some interlocking directorates. In granting authority to make sales at market-based rates, the FERC typically also grants blanket approval for certain obligations, such as those related to the issuance of securities.

As of the date of this prospectus, a number of EME's operating projects, including the Homer City facilities and the Illinois Plants, were subject to the FERC ratemaking regulation under the Federal Power Act. EME's future domestic non-qualifying facility independent power projects will also be subject to the FERC jurisdiction on rates.

Public Utility Regulatory Policies Act of 1978

PURPA provides two primary benefits to qualifying facilities. First, all cogeneration facilities that are qualifying facilities are exempt from certain provisions of the Federal Power Act and regulations of the FERC thereunder. Second, the FERC regulations promulgated under PURPA require that electric utilities purchase electricity generated by qualifying facilities at a price based on the purchasing utility's avoided cost (unless, pursuant to EPAct 2005, the FERC determines that the relevant market meets certain conditions for competitive, nondiscriminatory access), and that the utilities sell back up power to the qualifying facility on a nondiscriminatory basis. The FERC's regulations also permit qualifying facilities and utilities to negotiate agreements for utility purchases of power at prices different from the utility's avoided costs. While it had been common for utilities to enter into long-term contracts with qualifying facilities in order, among other things, to facilitate project financing of independent power facilities and to reflect the deferral by the utility of capital costs for new plant additions, increasing competition and the development of new power markets have resulted in a trend toward shorter term power contracts that would place greater risk on the project owner.

If one of the projects in which EME has an interest were to lose its status as a qualifying cogeneration facility, the project would no longer be entitled to the qualifying facility-related exemptions from regulation. As a result, the project could become subject to rate regulation by the FERC under the Federal Power Act and additional state regulation. Loss of qualifying facility status could also trigger defaults under covenants to maintain qualifying facility status in the project's power sales agreements, steam sales agreements and financing agreements and result in termination, penalties or acceleration of indebtedness under such agreements. If a power purchaser were to cease taking and paying for electricity or were to seek to obtain refunds of past amounts paid because of the loss of qualifying facility status, EME cannot provide assurance that the costs incurred in connection with the project could be recovered through sales to other purchasers. Moreover, EME's business and financial condition could be adversely affected if regulations or legislation were modified or enacted that changed the standards applicable to EME's facilities for maintaining qualifying facility status or that eliminated or reduced the benefits and exemptions currently enjoyed by EME's qualifying facilities. Loss of qualifying facility status on a retroactive basis could lead to, among other things, fines and penalties, or claims by a utility customer for the refund of payments previously made.

EPAct 2005 made several important amendments to PURPA, including the elimination of qualifying facility ownership restrictions, elimination of the requirement that electric utilities enter into new contracts to purchase electricity from qualifying facilities that have access to wholesale power markets that meet specified criteria or sell energy to existing qualifying facilities in states where there is retail electricity competition and no obligation under state law to make power sales, the granting of new authority to the FERC to ensure recovery by electric utilities of all prudently incurred costs associated with purchases of energy and capacity from qualifying facilities, and certain obligations upon electric utilities for interconnection and metering for qualifying facilities. The FERC has initiated several proceedings to promulgate rules and regulations to implement the mandates of EPAct 2005 with respect to PURPA, and EME is continuing to evaluate the effect of the legislation and proposed regulations on its business activities.

EME endeavors to monitor regulatory compliance by its qualifying facility projects in a manner that minimizes the risks of losing these projects' qualifying facility status. However, some factors necessary to maintain qualifying facility status are subject to risks of events outside EME's control. For example, loss of a thermal energy customer or failure of a thermal energy customer to take required amounts of thermal energy from a cogeneration facility that is a qualifying facility could cause a facility to fail to meet the requirements regarding the minimum level of useful thermal energy output. Upon the occurrence of this type of event, EME would seek to replace the thermal energy customer or find another use for the thermal energy that meets the requirements of PURPA.

Natural Gas Act

Many of the operating facilities that EME owns, operates or has investments in use natural gas as their primary fuel. Under the Natural Gas Act, the FERC has jurisdiction over certain sales of natural gas and over transportation and storage of natural gas in interstate commerce. The FERC has granted blanket authority to all persons to make sales of natural gas without restriction but continues to exercise significant oversight with respect to transportation and storage of natural gas services in interstate commerce.

Transmission of Wholesale Power

Generally, projects that sell power to wholesale purchasers other than the local utility to which the project is interconnected require the transmission of electricity over power lines owned by others. This transmission service over the lines of intervening transmission owners is also known as wheeling. The prices and other terms and conditions of transmission contracts are regulated by the FERC when the entity providing the transmission service is a jurisdictional public utility under the Federal Power Act.

The Energy Policy Act of 1992 laid the groundwork for a competitive wholesale market for electricity by, among other things, expanding the FERC's authority to order electric utilities to transmit third-party electricity over their transmission lines, thus allowing qualifying facilities under PURPA, power marketers and those qualifying as EWGs under PUHCA 1935 to more effectively compete in the wholesale market.

In 1996, the FERC issued Order No. 888, also known as the Open Access Rules, which require utilities to offer eligible wholesale transmission customers open access on utility transmission lines on a comparable basis to the utilities' own use of the lines and directed jurisdictional public utilities that control a substantial portion of the nation's electric transmission networks to file uniform, non-discriminatory open access tariffs containing the terms and conditions under which they would provide such open access transmission service. The FERC subsequently issued Order Nos. 888-A, 888-B and 888-C to clarify the terms that jurisdictional transmitting utilities are required to include in their open access transmission tariffs and Order No. 889, which required those transmitting utilities to abide by specified standards of conduct when using their own transmission systems to make wholesale sales of power, and to post specified transmission information, including information about transmission requests and availability, on a publicly available computer bulletin board.

On February 15, 2007, the FERC issued Order No. 890 with the stated intent of promoting competition in wholesale power markets and strengthening the electric power grids. Order No. 890 is designed to strengthen the Open Access Rules embodied in Order No. 888, increase transparency in the rules applicable to planning and use of the transmission system, make undue discrimination in transmission easier to detect, and facilitate the FERC's enforcement efforts in remedying such discrimination. Public utility transmission providers, including RTOs and ISOs, are required to make changes in their tariffs to comply with Order No. 890. Order No. 890 will take effect within 60 days of its publication in the Federal Register, which is expected to occur within 30 days of its issuance.

See " Overview of Facilities Illinois Plants Transmission" for further discussion of developments and other transmission issues affecting the Illinois Plants.

Illinois Auction Challenges

Legal actions have been instituted against successful participants in the 2006 Illinois power procurement auction, including EMMT. For further discussion, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Contractual Obligations, Commitments and Contingencies Contingencies Challenges of Illinois Power Procurement Auction Results."

Environmental Matters and Regulations

See the discussion on environmental matters and regulations in "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Environmental Matters and Regulations."

Employees

At June 30, 2007, EME and its subsidiaries employed 1,778 people, including:

- approximately 737 employees at the Illinois Plants covered by a collective bargaining agreement governing wages, certain benefits and working conditions. This collective bargaining agreement will expire on December 31, 2009. Midwest Generation also has a separate collective bargaining agreement governing retirement, health care, disability and insurance benefits that expires on June 15, 2010; and

- approximately 193 employees at the Homer City facilities covered by a collective bargaining agreement governing wages, benefits and working conditions. This collective bargaining agreement, which expired on December 31, 2006, was extended to December 31, 2007 by mutual agreement.

EME's Relationship with Certain Affiliated Companies

EME is an indirect subsidiary of Edison International. Edison International is a holding company. Edison International is also the corporate parent of SCE, an electric utility that serves customers in California.

MEHC

On June 8, 2001, Edison International created MEHC as a wholly owned indirect subsidiary. MEHC's principal asset is EME's common stock. During 2001, MEHC issued $800 million of 13.50% senior secured notes due 2008. The senior secured notes were secured by a first priority security interest in EME's common stock. On May 7, 2007, MEHC purchased substantially all of its senior secured notes with a dividend payment from EME.

On June 25, 2007, MEHC redeemed in full its senior secured notes. As a result of the redemption, EME is no longer subject to financial and investment restrictions that were contained in the indenture pursuant to which the senior secured notes were issued. Following the redemption, MEHC no longer files reports with the SEC.

Properties

EME leases its principal office in Irvine, California. The office lease is for approximately 60,000 square feet and expires on December 31, 2010. EME also leases office space in Chicago, Illinois; Chantilly, Virginia; Boston, Massachusetts; and Washington D.C. The Chicago lease is for approximately 41,000 square feet and expires on December 31, 2014. The Chantilly lease is for approximately 30,000 square feet and expires on March 31, 2010 and has been subleased since May 2001. The Boston lease is for approximately 41,000 square feet and expires on July 31, 2017. The Washington D.C. lease is immaterial.

The following table shows, as of June 30, 2007, the material properties owned or leased by EME's subsidiaries and affiliates. Each property represents at least five percent of EME's income before tax or is one in which EME has an investment balance greater than $50 million. Most of these properties are subject to mortgages or other liens or encumbrances granted to the lenders providing financing for the plant or project.

Plant	Location	Interest in Land	Plant Description
Homer City	Pittsburgh, Pennsylvania	Owned	Coal-fired generation facility
Illinois Plants	Northeast Illinois	Owned	Coal, oil/gas-fired generation facilities
Sunrise	Fellows, California	Leased	Combined cycle generation facility
Sycamore	Oildale, California	Leased	Natural gas-turbine cogeneration facility
Watson	Carson, California	Leased	Natural gas-turbine cogeneration facility

Legal Proceedings

FERC Notice Regarding Investigatory Proceeding against EMMT

At the end of October 2006, EMMT was advised by the enforcement staff at the FERC that it is prepared to recommend that the FERC initiate a formal investigatory proceeding and seek monetary sanctions against EMMT for alleged violation of the FERC's rules with respect to certain bidding practices employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Should a formal proceeding be commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with the FERC's rules and intends to contest vigorously any allegation of violation. EME cannot predict at this time the outcome of this matter or estimate the possible liability should the outcome be adverse.

Midwest Generation Potential Environmental Proceeding

On July 31, 2007, the US EPA issued a NOV to Midwest Generation and Commonwealth Edison. In the NOV, the US EPA alleges that, beginning in the early 1990's and into 2003, Midwest Generation or Commonwealth Edison performed construction projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration requirements and of the New Source Performance Standards of the Clean Air Act, including alleged requirements to obtain a construction permit and to install Best Available Control Technology at the time of the projects. The US EPA also alleges that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the Clean Air Act. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. Midwest Generation intends to meet with the US EPA to discuss the alleged violations. Midwest Generation is investigating the claims made by the US EPA in the NOV and potential responses and cannot predict at this time what effect this matter may have on its facilities, its results of operations or financial position.

DESCRIPTION OF THE NEW NOTES

In this Description of the New Notes, references to EME, we, our, ours and us refer only to Edison Mission Energy, and not to any of our direct or indirect subsidiaries or affiliates. The following description is a summary of certain provisions of the Indentures and the New Notes. It does not restate the Indenture and the New Notes in their entirety. We urge you to read the Indenture and the New Notes because they, and not this description, define your rights as a holder of these New Notes. You may obtain a copy of the Indenture and the New Notes from us by writing to us at 18101 Von Karman Avenue, Suite 1700, Irvine, California 92612.

General

We issued the Old Notes and will issue the New Notes under an Indenture, dated as of May 7, 2007, between us and Wells Fargo Bank, National Association, as Trustee. Reference to the Notes includes the New Notes unless the context otherwise requires. The Notes are unsecured senior obligations of ours and will rank equal in right of payment with all our other unsubordinated indebtedness. Because we conduct substantially all our business through numerous subsidiaries, all existing and future liabilities of our direct and indirect subsidiaries are and will be effectively senior to the Notes. The Notes are not guaranteed by, or otherwise be obligations of, our project subsidiaries and project affiliates, or our other direct and indirect subsidiaries and affiliates.

We issued the Old Notes in an offering exempt from registration. In this exchange offer, we will issue $1,200,000,000 in aggregate principal amount of New Tranche A Notes in exchange for the same amount of Old Tranche A Notes, $800,000,000 in aggregate principal amount of New Tranche B Notes in exchange for the same amount of Old Tranche B Notes and $700,000,000 in aggregate principal amount of New Tranche C Notes in exchange for the same amount of Old Tranche C Notes. The New Tranche A Notes and the Old Tranche A Notes (collectively, the "Tranche A Notes") will bear interest at the rate of 7.00% per annum, the New Tranche B Notes and the Old Tranche B Notes (collectively, the "Tranche B Notes") will bear interest at the rate of 7.20% per annum and the New Tranche C Notes and Old Tranche C Notes (collectively, the "Tranche C Notes") will bear interest at the rate of 7.625% per annum. We will pay interest on the New Notes on each May 15 and November 15, beginning on November 15, 2007, to the holders of record on the immediately preceding May 1 and November 1. Interest on the New Notes will accrue from the most recent date to which interest has been paid or, if no interest has been paid, from May 7, 2007. Interest will be computed on the basis of a 360-day year consisting of twelve 30-day months.

The New Notes will be in denominations of $2,000 and any integral multiple of $1,000 in excess thereof.

We may issue additional series of Notes under the Indenture from time to time in accordance with the conditions described therein.

Repurchase of Notes at the Option of the Holder upon a Change of Control

The Indenture provides that in the event a Change of Control Triggering Event (as defined below) occurs, each holder of Notes will have the right, at such holder's option, pursuant to an irrevocable and unconditional offer by us (the "*Change of Control Offer*"), to require us to repurchase all or any part of such holder's Notes (provided, that the principal amount of such Notes must be $2,000 and integral multiples of $1,000 in excess of $2,000) on a date (the "*Change of Control Purchase Date*") that is no later than 60 business days after the occurrence of such Change of Control Triggering Event, at a cash price equal to 101% of the principal amount thereof (the "*Change of Control Purchase Price*"), together with accrued and unpaid interest, if any, and Liquidated Damages, if any, to the Change of Control Purchase Date. The Change of Control Offer shall be made within 30 business days following such Change of Control Triggering Event and shall remain open for at least 30 business days following its commencement (the "*Change of Control Offer Period*"). Upon expiration of the Change of Control Offer Period, we promptly shall purchase all Notes properly tendered in response to the Change of Control Offer.

As used herein, a "*Change of Control Triggering Event*" shall be deemed to occur if (a) a Change of Control occurs and (b) during the period beginning on the earlier of (i) the date of the public notice of the intention of EME or Edison International to effect such Change of Control and (ii) the occurrence of such Change of Control and ending 90 days after the occurrence of such Change of Control, (x) if three rating agencies are continuing to provide ratings for the Notes on such date, more than one of the rating agencies rating the Notes at such time shall downgrade, below the rating as of the date of the Indenture, its respective rating of the Notes as a result of such Change of Control or (y) if fewer than three rating agencies are continuing to provide ratings for the Notes on such date, any of the rating agencies rating the Notes at such time shall downgrade, below the rating as of the date of the Indenture, its respective rating of the Notes as a result of such Change of Control. "*Change of Control*" means the occurrence of any of the following:

- the adoption of a plan relating to our liquidation or dissolution;

- the consummation of any transaction (including any merger or consolidation) the result of which is that any "*person*" (as that term is used in Section 13(d) of the Exchange Act) becomes the direct beneficial owner of more than 50% of our voting stock, other than (a) Edison International or (b) any entity at least a majority of the voting stock of which is directly or indirectly owned by (i) Edison International or (ii) substantially the same holders of the voting stock of Edison International immediately before any transaction which created such entity, in each case measured by voting power rather than number of shares and calculated on a diluted basis; or

- the direct or indirect sale, lease or conveyance of all or substantially all our assets and our subsidiaries taken as a whole to any "*person*" (as defined above) other than (a) Edison International or (b) any entity at least a majority of the voting stock of which is directly or indirectly owned by (i) Edison International or (ii) substantially the same holders of the voting stock of Edison International immediately before any transaction which created such entity, measured by voting power rather than number of shares and calculated on a diluted basis.

On or before the Change of Control Purchase Date, we will (i) accept for payment Notes or portions thereof properly tendered pursuant to the Change of Control Offer, (ii) deposit with the paying agent cash sufficient to pay the Change of Control Purchase Price (together with accrued and unpaid interest, if any, and Liquidated Damages, if any) of all Notes so tendered and (iii) deliver to the trustee Notes so accepted together with an officers' certificate listing the Notes or portions thereof being purchased by us. The paying agent promptly will pay the holders of Notes so accepted an amount equal to the Change of Control Purchase Price (together with accrued and unpaid interest, if any, and Liquidated Damages, if any), and the trustee promptly will authenticate and deliver to such holders a new Note equal in principal amount to any unpurchased portion of the Note surrendered. Any Notes not so accepted will be delivered promptly by us to the Holder thereof. We publicly will announce the results of the Change of Control Offer on or as soon as practicable after the Change of Control Purchase Date.

Our ability to pay such purchase price is, and may in the future be, limited by the terms of our secured corporate credit facility, as the same may be amended or other agreements relating to our senior debt. The occurrence of certain of the events that would constitute a Change of Control may constitute a default under the credit facility, as the same may be amended. Future indebtedness of ours may contain prohibitions of certain events which would constitute a Change of Control or require us to offer to redeem such indebtedness upon a Change of Control. Moreover, the exercise by the holders of the Notes of their right to require us to purchase the Notes could cause a default under such future indebtedness, even if the Change of Control itself does not, due to the financial effect of such purchase on us. Finally, our ability to pay cash to holders of Notes upon a purchase may be limited by our then existing financial resources. There can be no assurance that sufficient funds will be available when necessary to make any required purchases.

Any Change of Control Offer will be made in compliance with any and all applicable laws, rules and regulations, including, if applicable, Regulation 14E under the Exchange Act and the rules thereunder and any and all other applicable U.S. Federal and state securities laws. To the extent that the provisions of any securities laws or regulations conflict with the provisions of this covenant, our compliance or compliance by Edison International or any of our or its subsidiaries with such laws and regulations shall not in and of itself cause a breach of our or their obligations under such covenant.

Notwithstanding the foregoing, we shall not be required to make a Change of Control Offer upon a Change of Control Triggering Event if a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to a Change of Control Offer made by us and purchases all Notes properly tendered and not withdrawn under the Change of Control Offer.

Redemption

We may redeem all or a part of any Tranche of the Notes at any time, upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder's registered address, at a redemption price equal to 100% of the principal amount of the applicable Tranche of Notes redeemed plus the Applicable Premium (as defined below) as of, and accrued and unpaid interest and Liquidated Damages (as defined below), if any, to the redemption date, subject to the rights of holders of the applicable Tranche of Notes on the relevant record date to receive interest due on the relevant interest payment date.

Any Notes issued under an additional series of Notes will be subject to the redemption provisions in the supplemental indenture issued with respect to such series. Any additional Tranche A Notes, Tranche B Notes or Tranche C Notes issued after the date of the Indenture will be subject to the applicable redemption provisions and will be deemed "Initial Notes" under the Indenture.

"*Applicable Premium*" means:

(1) with respect to any New Tranche A Notes on any redemption date, the greater of:

(a) 1.0% of the principal amount of the New Tranche A Note; or

(b) the excess of:

(i) the present value at such redemption date of (A) 100% of the principal amount of the New Tranche A Note at May 15, 2017 plus (B) all required interest payments due on the New Tranche A Note through May 15, 2017 (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over

(ii) the principal amount of the New Tranche A Note, if greater;

(2) with respect to any New Tranche B Notes on any redemption date, the greater of:

(a) 1.0% of the principal amount of the New Tranche B Note; or

(b) the excess of:

(i) the present value at such redemption date of (A) 100% of the principal amount of the New Tranche B Note at May 15, 2019 plus (B) all required interest payments due on the New Tranche B Note through May 15, 2019 (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over

(ii) the principal amount of the New Tranche B Note, if greater; and

(3) with respect to any New Tranche C Notes on any redemption date, the greater of:

(a) 1.0% of the principal amount of the New Tranche C Note; or

(b) the excess of:

(i) the present value at such redemption date of (A) 100% of the principal amount of the New Tranche C Note at May 15, 2027 plus (B) all required interest payments due on the New Tranche C Note through May 15, 2027 (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over

(ii) the principal amount of the New Tranche C Note, if greater.

"*Treasury Rate*" means, as of any redemption date, the yield to maturity as of such redemption date of United States Treasury securities with a constant maturity (as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) that has become publicly available at least two business days prior to the redemption date (or, if such Statistical Release is no longer published, any publicly available source of similar market data)) most nearly equal to the period from the redemption date to (i) May 15, 2017 with respect to the New Tranche A Notes; (ii) May 15, 2019 with respect to the New Tranche B Notes; and (iii) May 15, 2027 with respect to the New Tranche C Notes; provided, however, that if the period from the redemption date to (i) May 15, 2017 with respect to the New Tranche A Notes; (ii) May 15, 2019 with respect to the New Tranche B Notes; and (iii) May 15, 2027 with respect to the New Tranche C Notes, is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year will be used.

Certain Covenants

Restrictions on Liens

We will agree not to pledge, mortgage, hypothecate or permit to exist any mortgage, pledge or other lien upon any property at any time directly owned by us to secure any indebtedness for money borrowed which is incurred, issued, assumed or guaranteed by us ("Indebtedness"), without providing for the Notes to be equally and ratably secured with any and all such Indebtedness and with any other Indebtedness similarly entitled to be equally and ratably secured; provided, however, that this restriction will not apply to, or prevent the creation or existence of:

(1) liens existing at the original date of issuance of the Notes;

(2) purchase money liens which do not exceed the cost or value of the purchased property;

(3) other liens not to exceed 15% of our Consolidated Net Tangible Assets (as defined below); and

(4) liens granted in connection with extending, renewing, replacing or refinancing in whole or in part the Indebtedness (including, without limitation, increasing the principal amount of such Indebtedness) secured by liens described in clauses (1) through (3) above.

"*Consolidated Net Tangible Assets*" means, as of any date of determination, the total amount of all of our assets, determined on a consolidated basis in accordance with generally accepted accounting principles as of such date, less the sum of:

(a) our consolidated current liabilities, determined in accordance with generally accepted accounting principles; and

(b) our assets that are properly classified as intangible assets in accordance with generally accepted accounting principles, except for any intangible assets which are distribution or related contracts with an assignable value.

If we propose to pledge, mortgage or hypothecate any property at any time directly owned by us to secure any Indebtedness, other than as permitted by clauses (1) through (4) of the second previous paragraph, we will agree to give prior written notice thereof to the Trustee, who will give notice to the holders of Notes, and we will further agree, prior to or simultaneously with such pledge, mortgage or hypothecation, effectively to secure all the Notes equally and ratably with such Indebtedness.

This covenant will not restrict the ability of our subsidiaries and affiliates to pledge, mortgage, hypothecate or permit to exist any mortgage, pledge or lien upon their assets, in connection with project financings or otherwise.

Merger, Consolidation, Sale, Lease or Conveyance

We will agree not to merge or consolidate with or into any other person and we will agree not to sell, lease or convey all or substantially all of our assets to any person, unless (1) we are the continuing corporation, or the successor corporation or the person that acquires all or substantially all of our assets is a corporation organized and existing under the laws of the United States or a State thereof or the District of Columbia and expressly assumes all our obligations under the Notes and the Indenture, (2) immediately after such merger, consolidation, sale, lease or conveyance, there is no default or Event of Default (as defined below) under the Indenture, (3) if, as a result of the merger, consolidation, sale, lease or conveyance, any or all of our property would become the subject of a lien that would not be permitted by the Indenture, we secure the Notes equally and ratably with the obligations secured by that lien and (4) we deliver or cause to be delivered to the Trustee an officers' certificate and opinion of counsel each stating that the merger, consolidation, sale, lease or conveyance comply with the Indenture.

The meaning of the term "all or substantially all of the assets" has not been definitely established and is likely to be interpreted by reference to applicable state law if and at the time the issue arises and will be dependent on the facts and circumstances existing at the time.

Reporting Obligations

We will agree to furnish or cause to be furnished to holders of Notes copies of our annual reports and of the information, documents and other reports that we are required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act within 15 days after we file them with the SEC.

In addition, we will agree that, for so long as any of the respective Notes remain outstanding, if at any time we are not required to file with the SEC the reports required by the preceding paragraph, we will furnish to the holders of such Notes and to securities analysts and prospective investors, upon their request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

Additional Covenants

Subject to certain exceptions and qualifications, we will agree in the Indenture to do, among other things, the following:

(1) deliver to the Trustee copies of all reports that we file with the SEC;

(2) deliver to the Trustee annual officers' certificates with respect to our compliance with our obligations under the Indenture;

(3) maintain our corporate existence, subject to the provisions described above relating to mergers and consolidations; and

(4) pay our taxes when due, except when we are contesting such taxes in good faith.

Modification of the Indenture

The Indenture will contain provisions permitting us and the Trustee, with the consent of the holders of at least a majority in aggregate principal amount of Notes then outstanding, to modify or amend the Indenture or the rights of the holders of Notes. However, no such modification or amendment may, without the consent of the holder of each outstanding Note affected thereby:

(a) change the stated maturity of the principal of, or extend the time of payment of interest on, any Note;

(b) reduce the principal amount of, or interest on, any Note;

(c) change the place or currency of payment of principal of, or interest on, any Note;

(d) reduce any amount payable upon the redemption of any Note; or

(e) impair the right to institute suit for the enforcement of any payment on or with respect to any Note.

In addition, without the consent of the holders of all Notes then outstanding, no such modification or amendment may:

(x) reduce the percentage in principal amount of outstanding Notes the consent of whose holders is required for modification or amendment of the Indenture;

(y) reduce the percentage in principal amount of outstanding Notes necessary for waiver of compliance with certain provisions of the Indenture or for waiver of certain defaults; or

(z) modify such provisions with respect to modification and waiver.

The holders of at least a majority in principal amount of the outstanding Notes may waive our compliance with certain restrictive provisions of the Indenture. The holders of a majority in principal amount of the outstanding Notes may waive any past default under the Indenture, except a default in the payment of principal or interest and certain covenants and provisions of the Indenture which cannot be amended without the consent of the holder of each outstanding Note affected.

We and the Trustee may, without the consent of any holder of Notes, amend the Indenture and the New Notes for the purpose of curing any ambiguity, or of curing, correcting or supplementing any defective provision thereof, or in any manner that we and the Trustee may determine is not inconsistent with the Indenture and the New Notes and will not adversely affect the interest of any holder of Notes.

Events of Default

Each of the following will be an "Event of Default" under the Indenture:

(a) our failure to pay any interest on any Note when due, which failure continues for 30 days; or

(b) our failure to pay principal or premium when due; or

(c) our failure to perform any other covenant in the Notes or the Indenture for a period of 90 days after the Trustee or the holders of at least 25% in aggregate principal amount of the Notes gives us written notice of our failure to perform; or

(d) an event of default occurring under any of our instruments under which there may be issued, or by which there may be secured or evidenced, any Indebtedness for money borrowed that has resulted in the acceleration of such Indebtedness, or any default occurring in payment of any such Indebtedness at final maturity (and after the expiration of any applicable grace periods), other than

(i) Indebtedness which is payable solely out of the property or assets of a partnership, joint venture or similar entity of which we or any of our subsidiaries or affiliates is a participant, or which is secured by a lien on the property or assets owned or held by such entity, without further recourse to or liability of us; or

(ii) Indebtedness not exceeding $20,000,000; or

(e) one or more nonappealable final judgments, decrees or orders of any court, tribunal, arbitrator, administrative or other governmental body or similar entity for the payment of money aggregating more than $20,000,000 shall be rendered against us (excluding the amount thereof covered by insurance) and shall remain undischarged, unvacated and unstayed for more than 90 days, except while being contested in good faith by appropriate proceedings; or

(f) certain events of bankruptcy, insolvency or reorganization in respect of us.

If any Event of Default (other than an Event of Default due to certain events of bankruptcy, insolvency or reorganization) has occurred and is continuing, either the Trustee or the holders of not less than 25% in principal amount of the New Notes outstanding under the Indenture may declare the principal of all Notes under the Indenture and interest accrued thereon to be due and payable immediately.

The Trustee will be entitled, subject to the duty of the Trustee during a default to act with the required standard of care, to be indemnified by the holders of Notes before proceeding to exercise any right or power under the Indenture at the request of such holders. Subject to such provisions in the Indenture for the indemnification of the Trustee and certain other limitations, the holders of a majority in principal amount of the Notes then outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee.

No holder of Notes may institute any action against us under the Indenture (except actions for payment of overdue principal or interest) unless:

(1) such holder previously has given the Trustee written notice of the default and continuance thereof;

(2) the holders of not less than 25% in principal amount of the Notes then outstanding have requested the Trustee to institute such action and offered the Trustee reasonable indemnity;

(3) the Trustee has not instituted such action within 60 days of the request; and

(4) the Trustee has not received direction inconsistent with such written request from the holders of a majority in principal amount of the Notes then outstanding.

Defeasance and Covenant Defe