UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A
Amendment No. 1
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2007

Commission File Number 333-68630

Edison Mission Energy
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**95-4031807** (I.R.S. Employer Identification No.)
18101 Von Karman Avenue, Suite 1700 **Irvine, California** (Address of principal executive offices)	**92612** (Zip Code)

Registrant's telephone number, including area code: **(949) 752-5588**

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

None	**Not Applicable**
(Title of Class)	(Name of each exchange on which registered)

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

Common Stock, par value $0.01 per share
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☒

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

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

Aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant as of June 30, 2007: $0. Number of shares outstanding of the registrant's Common Stock as of February 27, 2008: 100 shares (all shares held by an affiliate of the registrant).

The registrant meets the conditions set forth in General Instruction I.(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K/A under the reduced disclosure format.

DOCUMENTS INCORPORATED BY REFERENCE

None

EXPLANATORY NOTE

This Amendment No. 1 to Edison Mission Energy's (EME) annual report on Form 10-K/A for the fiscal year ended December 31, 2007 is being filed in order to correct technical filing requirements on the original signature page. This Amendment No. 1 does not amend, modify or update any other information or disclosures to reflect developments since the original date of filing of the annual report on Form 10-K on February 27, 2008. Accordingly, this Form 10-K/A should be read in conjunction with EME's filings made with the Securities and Exchange Commission subsequent to the filing of the original annual report on Form 10-K.

In addition, pursuant to Rule 12b-15 of the Securities Exchange Act of 1934, as amended, this Amendment No. 1 includes updated certifications from the Chief Executive Officer and Chief Financial Officer.

TABLE OF CONTENTS

GLOSSARY

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Ameren	Ameren Corporation
ARO	asset retirement obligations
Btu	British thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Commonwealth Edison	Commonwealth Edison Company
CPS	Combined Pollutant Standard
DOJ	United States Department of Justice
EIA	Energy Information Administration
EME	Edison Mission Energy
EME Homer City	EME Homer City Generation L.P.
EMMT	Edison Mission Marketing & Trading, Inc.
EPAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ERP	enterprise resource planning
EWG(s)	exempt wholesale generator(s)
Exelon Generation	Exelon Generation Company LLC
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 46(R)	Financial Accounting Standards Interpretation No. 46, "Consolidation of Variable Interest Entities"
FIN No. 39-1	Financial Accounting Standards Board Staff Position No. 39-1, "Amendment of FASB Interpretation No. 39"
FIN No. 48	Financial Accounting Standards Interpretation No. 48, "Accounting for Uncertainty in Income Taxes"
Fitch	Fitch Ratings
FPA	Federal Power Act
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GWh	gigawatt-hours
Illinois EPA	Illinois Environmental Protection Agency
Illinois Plants	EME's largest power plants (fossil fuel) located in Illinois
IPM	a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%)
ISO(s)	independent system operator(s)
LIBOR	London Interbank Offered Rate

MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MEHC	Mission Energy Holding Company
Midwest Generation	Midwest Generation, LLC
MISO	Midwest Independent Transmission System Operator
MMBtu	million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	megawatts
MWh	megawatt-hours
NAPP	Northern Appalachian
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NO_X	nitrogen oxide
NSR	New Source Review
NYISO	New York Independent System Operator
PADEP	Pennsylvania Department of Environmental Protection
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
PRB	Powder River Basin
PUHCA 1935	Public Utility Holding Company Act of 1935 (as amended)
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978 (as amended)
RPM	reliability pricing model
RTO(s)	regional transmission organization(s)
S&P	Standard & Poor's Ratings Services
SCE	Southern California Edison Company
SCR	selective catalytic reduction
SECA(s)	Seams Elimination Cost Adjustment(s)
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 98	Statement of Financial Accounting Standards No. 98, "Sale-Leaseback Transactions Involving Real Estate"
SFAS No. 123(R)	Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment"
SFAS No. 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS No. 141(R)	Statement of Financial Accounting Standards No. 141(R), "Business Combinations"
SFAS No. 144	Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS No. 155	Statement of Financial Accounting Standards No. 155, "Accounting for Certain Hybrid Financial Instruments"

SFAS No. 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements"
SFAS No. 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-Retirement Plans"
SFAS No. 159	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. 160	Statement of Financial Accounting Standards No. 160, "Noncontrolling Interests in Consolidated Financial Statements"
SIP(s)	state implementation plan(s)
SO_2	sulfur dioxide
US EPA	United States Environmental Protection Agency

PART I

ITEM 1. 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 an indirect subsidiary of Edison International. 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 December 31, 2007, EME's subsidiaries and affiliates owned or leased interests in 28 operating projects with an aggregate net physical capacity of 10,623 MW of which EME's capacity pro rata share was 9,453 MW. EME's operating projects primarily consist of coal-fired generating facilities, natural gas-fired facilities and wind farms. At December 31, 2007, eight wind projects totaling 447 MW of generating capacity were under construction.

EME is incorporated under the laws of the State of Delaware. EME's headquarters and principal executive offices are located at 18101 Von Karman Avenue, Suite 1700, Irvine, California 92612, and EME's telephone number is (949) 752-5588. Unless indicated otherwise or the context otherwise requires, references to EME in this annual report are with respect to EME and its consolidated subsidiaries and the partnerships or limited liability entities through which EME and its partners own and manage their project investments.

EME's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports, are electronically filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and are available on the Securities and Exchange Commission's internet web site at http://www.sec.gov.

Forward-Looking Statements

This annual report on Form 10-K/A contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements reflect EME's current expectations and projections about future events based on EME's knowledge of present facts and circumstances and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by EME that is incorporated in this annual report, or that refers to or incorporates this annual report, may also contain forward-looking statements. In this annual report 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 EME or its 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 EME's 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 EME's obligations to post collateral beyond the amounts currently expected, and the potential effect of such conditions on the ability of EME and its 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 EME or the electricity industry generally, including the market structure rules applicable to each market;
- environmental laws and regulations at both state and federal levels, that could require additional expenditures or otherwise affect EME's cost and manner of doing business;
- the ability of EME to successfully implement its 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 EME's generating facilities and/or increased access by competitors to EME's markets as a result of transmission upgrades;
- the ability of EME 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 EME and its 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
- EME's continued participation and the continued participation by EME's subsidiaries in tax-allocation and payment agreements with EME's respective affiliates.

Certain of the risk factors listed above are discussed in more detail in "Item 1A. Risk Factors" and in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations— Market Risk Exposures." Additional information about the risk factors listed above and other risks and uncertainties is contained throughout this annual report. Readers are urged to read this entire annual report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect EME's business. Forward-looking statements speak only as of the date they are made, and EME is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by EME with the Securities and Exchange Commission.

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;
  - entering into power sales contracts and other hedging activities to smooth cash flow from merchant power projects; and
  - effective participation in regulatory rule-making in markets where EME operates.
- Growing EME's business by expanding generation assets and building non-asset trading services 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
  - leveraging EME's knowledge and expertise in trading to enhance financial performance within a disciplined risk management structure.
- Reducing the emissions profile of EME's projects through commercially prudent installation of environmental retrofits to existing coal and gas plants while increasing generation from renewable projects including:
  - exploring commercially feasible methods for capturing and sequestering carbon dioxide through environmental retrofits on existing projects as well as developing new clean-coal generation projects; and
  - dedicated efforts to expand renewable development of solar projects to complement ongoing wind development efforts.

Description of the Industry

Electric Power Industry

Historically, utilities and government-owned power agencies were the only producers of bulk electric power intended for sale to third parties in the United States. However, the United States electric industry, including companies engaged in providing generation, transmission, distribution and ancillary services, has undergone significant deregulation over the last three decades, which has led to increased competition. Most recently, through EPAct 2005, Congress recognized 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 developments discussed above, the FERC has encouraged the formation of ISOs and RTOs. In those areas where ISOs and 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."

In various regional markets, electricity market administrators have acknowledged that the markets for generating capacity do not provide sufficient revenues to enable existing merchant generators to recover all of their costs or to encourage new generating capacity to be constructed. Capacity auctions have been implemented in some markets, including PJM, to address this issue. This approach is currently expected to provide significant additional capacity revenues for independent power producers.

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 annual report, and the Homer City electric generating station located in Pennsylvania, which is referred to as the Homer City facilities in this annual report. The Illinois Plants and the Homer City facilities sell power into PJM. PJM originally covered Pennsylvania, New Jersey, and Maryland, and now extends from North Carolina to Illinois. 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.

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

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. 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 "Item 7. 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, financial institutions, and other independent power producers. Some of EME's competitors have a lower cost of capital than most independent power producers and, in the case of utilities, are often 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. These companies may also have competitive advantages as a result of their scale and the location of their generation facilities.

For a number of years, natural gas had been the fuel of choice for new power generation facilities for economic, operational and environmental reasons. While natural gas-fired facilities continue to be an important part of the nation's generation portfolio, some regulated utilities are constructing units powered by renewable resources, often with subsidies or under legislative mandate. New environmental regulations, particularly those that limit emissions of carbon dioxide and other greenhouse gases by electric generators, could put coal-fired plants at a disadvantage compared with power plants utilizing other fuels.

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 December 31, 2007, EME's operations consisted of ownership or leasehold interests in the following operating projects:

Projects	Location	Primary Electric Purchaser(2)	Fuel Type	Ownership Interest	Net Physical Capacity (in MW)	EME's Capacity Pro Rata Share (in MW)
Merchant Power Plants						
Illinois Plants(1)	Illinois	PJM	Coal/Oil/Gas	100%	5,776	5,776
Homer City(1)	Pennsylvania	PJM	Coal	100%	1,884	1,884
Contracted Power Plants						
Domestic						
Big 4 Projects						
Kern River(1)	California	SCE	Natural Gas	50%	300	150
Midway-Sunset(1)	California	SCE	Natural Gas	50%	225	113
Sycamore(1)	California	SCE	Natural Gas	50%	300	150
Watson	California	SCE	Natural Gas	49%	385	189
Westside Projects						
Coalinga(1)	California	PG&E	Natural Gas	50%	38	19
Mid-Set(1)	California	PG&E	Natural Gas	50%	38	19
Salinas River(1)	California	PG&E	Natural Gas	50%	38	19
Sargent Canyon(1)	California	PG&E	Natural Gas	50%	38	19
American Bituminous(1)	West Virginia	MPC	Waste Coal	50%	80	40
March Point	Washington	PSE	Natural Gas	50%	140	70
Sunrise(1)	California	CDWR	Natural Gas	50%	572	286
Huntington	New York	LIPA	Biomass	38%	25	9
San Juan Mesa(1)	New Mexico	SPS	Wind	75%	120	90
Sleeping Bear(1)	Oklahoma	PSCO	Wind	100%	95	95
Minnesota Wind projects(4)	Minnesota	NSPC/IPLC	Wind	75-99%(3)	83	75
Iowa Wind Projects						
Storm Lake(1)	Iowa	MEC	Wind	100%	109	109
Crosswinds(1)	Iowa	CBPC	Wind	99%(3)	21	21
Hardin(1)	Iowa	IPLC	Wind	99%(3)	15	15
Wildorado(1)	Texas	SPS	Wind	99.9%(3)	161	161
International						
Doga(1)	Turkey	TEDAS	Natural Gas	80%	180	144
Total					10,623	9,453

(1) Plant is operated under contract by an EME operations and maintenance subsidiary or plant is operated or managed directly by an EME subsidiary.

(2) Electric purchaser abbreviations are as follows:

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

(3) Represents EME's current ownership interest. If the project achieves a specified rate of return, EME's interest will decrease.

(4) Comprised of seven individual wind projects.

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	532
Fisk Station	Chicago, Illinois	owned	coal	326
Joliet Unit 6	Joliet, Illinois	owned	coal	290
Joliet Units 7 and 8	Joliet, Illinois	leased	coal	1,036
Powerton Station	Pekin, Illinois	leased	coal	1,538
Waukegan Station	Waukegan, Illinois	owned	coal	689(1)
Will County Station	Romeoville, Illinois	owned	coal	1,060(2)
Peaking Units				
Fisk	Chicago, Illinois	owned	oil/gas	197
Waukegan	Waukegan, Illinois	owned	oil/gas	108
Total				5,776

Other Plant or Site	Location
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 7 and 8. Midwest Generation shut down permanently Waukegan Station Unit 6 (100 MW) on December 21, 2007. For further discussion, see "Item 7. 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 Interstate Rule—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 "Item 7. 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 Interstate Rule—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.

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 "Item 7. 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 after their acquisition in 1999 was 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 had been 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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures."

Fuel Supply

Coal is used to fuel 5,471 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, 2007, Midwest Generation leased approximately 4,000 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 12 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 "Item 7. 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 in this annual report), 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 "Item 7. 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 "Item 7. 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 SO_2 and, on a seasonal basis, to their plants' emissions of NO_X. Emission allowances were acquired as part of the acquisition of the Homer City facilities and the Illinois Plants. Additional emission 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 "Item 7. 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 "Item 7. 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 "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies," for discussion of EME's accounting for this entity.

Kern River Project

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 Project

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 Project

EME owns a 50% partnership interest in Sycamore Cogeneration Company, which owns a 300 MW natural gas-fired cogeneration facility located near Bakersfield, California, which EME refers to as the Sycamore project. Sycamore Cogeneration's prior long-term power purchase agreement with SCE and its steam supply agreement with Chevron North America Exploration and Production Company, a wholly owned subsidiary of Chevron Corporation, both expired on December 31, 2007. Sycamore Cogeneration is currently selling electricity to SCE under the terms and conditions contained in its prior long-term power purchase agreement, with revised pricing terms as mandated by California Public Utilities

Commission Decision 07-09-040, dated September 20, 2007. EME expects that this arrangement will eventually be replaced by a new power purchase agreement between Sycamore and SCE, but cannot predict at this time whether or when this will occur. Sycamore Cogeneration entered into a new steam supply agreement with Chevron North America Exploration and Production Company that expires in 2013.

Watson Project

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. According to SCE, Watson Cogeneration's prior long-term power purchase agreement with SCE expired on December 31, 2007 (Watson Cogeneration contends that the agreement expires in April 2008). Watson Cogeneration is currently selling electricity to SCE under the terms and conditions contained in its prior long-term power purchase agreement, with revised pricing terms as mandated by California Public Utilities Commission Decision 07-09-040, dated September 20, 2007. EME expects that this arrangement will eventually be replaced by a new power purchase agreement between Watson and SCE, but cannot predict at this time whether or when this will occur. Watson Cogeneration currently sells power and steam to BP West Coast Products LLC under agreements that expire in April 2008. Watson and BP West Coast Products LLC have agreed to extend these two agreements; once extended, they will expire in 2013 or upon the termination of any new power purchase agreement executed between Watson and SCE, whichever is earlier.

Other Projects

Westside Projects

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 Project

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 Project

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 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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Results of Continuing Operations—Earnings from Unconsolidated Affiliates."

Sunrise Project

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 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 Project

EME owns a 75% interest in San Juan Mesa Wind Project LLC, which owns a 120 MW wind farm located near Elida, New Mexico, which EME refers to as the San Juan Mesa wind project. The project sells electricity to Southwestern Public Service Company, 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.

Sleeping Bear Wind Project

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. The project sells electricity to Public Service Company of Oklahoma, a unit of American Electric Power, under a 25-year power purchase agreement. The Sleeping Bear wind project achieved commercial operation effective October 2007.

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 Project

EME owns a 100% interest in Storm Lake Power Partners I, LLC, which owns a 109 MW wind farm 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 form a 21 MW wind farm located in northwestern Iowa, which EME refers to as the Crosswinds wind project. The projects sell electricity to Corn Belt Power Cooperative under 15-year (with a 5 year renewal option) power purchase agreements. 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 form a 15 MW wind farm located in western Iowa, which EME refers to as the Hardin wind project. The projects sell electricity to Interstate Power and Light Company under 20-year power purchase agreements. The Hardin wind project achieved commercial operation in May 2007.

Wildorado Wind Project

EME owns a 99.9% interest in Wildorado Wind, LLC, 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 Project

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

Overview of Projects under Construction

As of December 31, 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 or as a merchant wind generator.

Jeffers Wind Project

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 in 2008. 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& II Projects

EME owns a 100% interest in Mountain WindPower LLC, which owns a 61 MW wind farm and an 80 MW wind farm located in Wyoming, which EME refers to as the Mountain Wind I project and Mountain Wind II project, respectively. The Mountain Wind I project commenced construction during the second quarter of 2007 with completion scheduled during the second quarter of 2008. The Mountain Wind II project commenced construction during the third quarter of 2007 with completion scheduled during the third quarter of 2008. These projects plan to sell electricity to PacifiCorp under 20-year power purchase agreements.

Forward Wind Project

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. Construction of this project commenced during the second quarter of 2007 with completion scheduled during the second quarter of 2008. The project plans to sell electricity to Constellation NewEnergy under a 10-year power purchase agreement.

Lookout Wind Project

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. Construction of this project commenced during the second quarter of 2007 with completion scheduled during the second quarter of 2008. The project plans to sell electricity into PJM as a merchant wind generator.

Odin Wind Project

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. Construction of this project commenced during the second quarter of 2007 with completion scheduled during the second quarter of 2008. The project plans to sell electricity to Missouri River Energy Services under a 20-year power purchase agreement.

Goat Mountain Wind Project

EME owns a 99.9% interest in Goat Wind LP, which owns a 150 MW wind farm project in Texas, which EME refers to as the Goat Mountain wind project. The project consists of two phases. Construction of this project commenced during the third quarter of 2007 with Phase I (80 MW) 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 project plans to sell electricity into the ERCOT market as a merchant wind generator.

Spanish Fork Wind Project

EME owns a 100% interest in Spanish Fork Wind Farm 2, LLC, which owns a 19 MW wind farm located in Utah, which EME refers to as the Spanish Fork wind project. Construction of the project commenced during the fourth quarter of 2007 with completion scheduled during the second quarter of 2008. The project plans to sell electricity to PacifiCorp under a 20-year power purchase agreement.

Business Development

Renewable Projects

Wind Projects

EME has made significant investments in wind projects and expects to continue to do so over 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 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 (referred to as development 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. In addition to joint development agreements, EME may purchase wind projects from third-party developers in various stages of development, construction or operation. See "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 4. Acquisitions and Consolidations—Consolidations" for further discussion.

In general, EME funds development costs under joint development agreements through 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.

As of December 31, 2007, EME had a development pipeline of potential wind projects with a projected installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. Completion of development of a wind project may take a number of years due to factors that include local permit requirements, willingness of local utilities to purchase renewable power at sufficient prices to earn an appropriate rate of return, and availability and prices of equipment. Furthermore, successful completion of a wind project is dependent upon obtaining permits, an interconnection agreement(s) or other agreements necessary to support an investment. There is no assurance that each project included in the development pipeline currently or added in the future will be successfully completed.

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. Development efforts include feasibility studies, site development and acquisition, permitting, and contractual arrangements, including fuel supply and interconnection. Generally, it is expected that thermal projects in which EME invests will sell electricity under long-term power purchase contracts. EME may participate 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, and in hedging activities associated with EME's merchant wind energy 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 "Item 7. 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 "earnings at risk" to identify, measure, monitor and control its overall market risk exposure with respect to hedge positions of the Illinois Plants, the Homer City facilities, and the merchant wind projects, and "value at risk" to identify, measure, monitor and control its overall risk exposure in respect of its trading positions. The use of these measures allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify risk factors. Value at risk measures the possible loss, and earnings at risk measures the potential change in value of an asset or position, in each case over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of these measures and reliance on a single type of risk measurement tool, EME supplements these approaches 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 "Item 1A. 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 for the year ended December 31, 2007. In the past three fiscal years, 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 51%, 58% and 69% of EME's consolidated operating revenues for the years ended December 31, 2007, 2006 and 2005, respectively.

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 $1.25 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 "Item 7. 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 "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries 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 development, 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. In addition, EME is subject to the market rules, procedures, and protocols of the markets in which it participates.

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 FPA and with respect to certain interstate sales, transportation and storage of natural gas under the Natural Gas Act of 1938. 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 FPA 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 EWGs and foreign utility companies.

The Energy Policy Act of 2005

A comprehensive energy bill was enacted in August 2005. Known as "EPAct 2005," this comprehensive legislation included provisions for the repeal of PUHCA 1935, amendments to PURPA, merger review reform, the introduction of new regulations regarding transmission operation improvements, FERC authority to impose civil penalties for violation of its regulations, transmission rate reform, incentives for various generation technologies and the extension (originally through December 31, 2007, and subsequently extended through December 31, 2008) of production tax credits for wind and other specified types of generation. The FERC finalized rules to implement the congressionally mandated repeal of PUHCA 1935, effective February 8, 2006, and the enactment of PUHCA 2005. PUHCA 2005 is primarily a "books and records access" statute and does not give the FERC any new substantive authority under the FPA 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 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.

Federal Power Act

The FPA 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 FPA. EWGs certified in accordance with the FERC's rules under PUHCA 2005 and other non-qualifying facility independent power projects are subject to the FPA 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.

As of December 31, 2007, EME's power marketing subsidiaries, including EMMT, and a number of EME's operating projects, including the Homer City facilities and the Illinois Plants, were authorized by the FERC to make wholesale market sales of power at market-based rates and were subject to the FERC ratemaking regulation under the FPA. EME's future domestic non-qualifying facility independent power projects will also be subject to the FERC jurisdiction on rates.

In addition, the FPA grants the FERC jurisdiction over the sale or transfer of jurisdictional assets, including wholesale power sales contracts and 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. However, dispositions of EME's jurisdictional assets or certain types of financing arrangements may require FERC approval.

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 FPA and regulations of the FERC thereunder. Second, the FERC regulations promulgated under PURPA required 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 permitted qualifying facilities and utilities to negotiate agreements for utility purchases of power at prices different from the utility's avoided costs.

EPAct 2005 made several important amendments to PURPA, including:

- 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;
- 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. On October 20, 2006, FERC issued a final rule establishing a rebuttable presumption that any utility located in MISO, PJM, ISO New England, NYISO or ERCOT will be relieved from the must-purchase requirement with respect to qualifying facilities larger than 20 MW. With respect to other markets, and with respect to all qualifying facilities 20 MW or smaller, the utility bears the burden of showing that it qualifies for relief from the must-purchase requirement. Any electric utility seeking relief from the must-purchase requirement, regardless of location, must apply to the FERC for relief.

Several of EME's projects, including the Big 4 projects, the Westside projects, American Bituminous, and March Point, are qualifying cogeneration facilities. If one of the projects in which EME has an interest were to lose its qualifying facility status, 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 FPA 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, it might not be possible to recover the costs incurred in connection with the project 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.

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 FPA.

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.

Illinois Power Procurement

Prior Auction Rules

In February 2005, Commonwealth Edison and the Ameren Illinois utilities filed tariffs at the Illinois Commerce Commission proposing the adoption of what is known as a New Jersey style full requirement auction process for the procurement of power for the utilities' bundled customers beginning January 1, 2007. The Illinois Commerce Commission unanimously approved the competitive auction process on January 24, 2006.

In September 2006, the first Illinois power procurement auction was held according to the rules approved by the Illinois Commerce Commission. Through the auction, EMMT entered into two load requirements service contracts. Under the terms of these agreements, Midwest Generation is delivering, 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.

Legal actions, including a complaint at the FERC by the Illinois Attorney General and two class action lawsuits, were instituted against successful participants in the 2006 Illinois power procurement auction, including EMMT. 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. As part of the settlement, all auction-related complaints filed by the Illinois Attorney General at the FERC, the Illinois Commerce Commission and in the Illinois courts were dismissed and on December 24, 2007, the class action lawsuits were dismissed. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies—Contingencies—Settlement with Illinois Attorney General."

Power Procurement in the Future

The legislation that was signed into law on August 28, 2007 is referred to as the Illinois Power Agency Act. In addition to enacting the settlement and associated rate relief provisions, the Illinois Power Agency Act establishes a new process for Commonwealth Edison and the Ameren Illinois utilities to procure power for their bundled-rate customers. Beginning July 1, 2008, the two utilities will procure power for bundled-rate customers by means of those full requirements contracts that resulted from the September 2006 auction that have not yet expired, certain multi-year swap contracts that they entered into with their affiliates pursuant to the Illinois Power Agency Act, and a competitive request for proposal procurement of standard wholesale power products run by independent procurement administrators with the oversight and approval of the Illinois Commerce Commission. The Illinois Power Agency Act provides further that starting in June 2009, a newly created Illinois Power Agency will be responsible for the administration, planning and procurement of power for Commonwealth Edison and the Ameren Illinois utilities' bundled-rate customers using a portfolio-managed approach that is to include competitively procured standard wholesale products and renewable energy resources. The Illinois Commerce Commission will continue in its role of oversight and approval of the power planning and procurement for bundled retail customers of the utilities.

PJM Matters

On June 1, 2007, PJM implemented the RPM for capacity. The purpose of the RPM is to provide a long-term pricing signal for capacity resources. The RPM provides a mechanism for PJM to satisfy the region's need for generation capacity, the cost of which is allocated to load-serving entities through a locational reliability charge. Also on June 1, 2007, PJM implemented marginal losses for transmission for its competitive wholesale electric market. For further discussion regarding the RPM and recent auctions, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Commodity Price Risk—Capacity Price Risk."

Environmental Matters and Regulations

See the discussion on environmental matters and regulations in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations."

Employees

At December 31, 2007, EME and its subsidiaries employed 1,793 people, including:

- approximately 740 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 189 employees at the Homer City facilities covered by a collective bargaining agreement governing wages, benefits and working conditions. This collective bargaining agreement will expire on December 31, 2012.

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 Securities and Exchange Commission.

ITEM 1A. RISK FACTORS

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

EME's 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 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 ability of regional pools to pay market participants' settlement prices for energy and related products;
- 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 EME's 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 EME's 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 EME.

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

EME's business is subject to changes in fuel costs, which may negatively affect its 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 EME's expectations.

Although EME attempts to purchase fuel based on its known fuel requirements, it is 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 EME can sell its energy may not rise or fall at the same rate as a corresponding rise or fall in fuel costs. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Commodity Price Risk."

EME may not be able to hedge market risks effectively.

EME is exposed to market risks through its ownership and operation of merchant energy power plants and through its 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. EME uses forward contracts and derivative financial instruments, such as futures contracts and options, to manage market risks and exposure to fluctuating electricity and fuel prices. However, EME cannot provide assurance that these strategies will successfully mitigate market risks, or that they will not result in net losses.

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

The effectiveness of EME's 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, EME 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 EME's 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, EME cannot predict with precision the effect that risk management decisions may have on its business, operating results or financial position. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Margin, Collateral Deposits and Other Credit Support for Energy Contracts."

EME is exposed to credit and performance risk from third parties under supply and transportation contracts.

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

EME is subject to extensive energy industry regulation.

EME's operations are subject to extensive regulation by governmental agencies. EME's 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 FERC may impose various forms of market mitigation measures, including price caps and operating restrictions, where it determines that potential market power might exist and that the public interest requires mitigation. In addition, many of EME's facilities are subject to rules, restrictions and terms of participation imposed and administered by various RTOs and ISOs. For example, ISOs and 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 EME's 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 EME's business, results of operations or financial condition, nor is there any assurance that EME will be able to obtain and comply with all necessary licenses, permits and approvals for its projects. If projects cannot comply with all applicable regulations, EME's business, results of operations and financial condition could be adversely affected.

EME is subject to extensive environmental regulation and permitting requirements that may involve significant and increasing costs.

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

EME devotes significant resources to environmental monitoring, pollution control equipment and emission allowances to comply with environmental regulatory requirements. EME believes that it is currently in substantial compliance with environmental regulatory requirements. However, the US EPA has issued a NOV to Midwest Generation and Commonwealth Edison, the former owner of Midwest

Generation's coal-fired power plants, alleging violations of the CAA 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 EME's coal-fired plants. Also, coal plant emissions of NO_X and SO_2, mercury and particulates are subject to increased controls and mitigation expenses under current regulations and may be subject to new, possibly stricter, regulation in the future. The continued operation of EME's facilities, particularly its coal-fired facilities, is expected to require substantial capital expenditures for environmental controls.

For example, in December 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_X and SO_2 emissions at Midwest Generation's Illinois coal-fired power plants. Capital expenditures relating to controls contemplated by the agreement have been previously estimated as being in the range of approximately $2.7 billion to $3.4 billion through 2018. See "Item 7. 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 Interstate Rule—Illinois." 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 EME conducts its business. There is no assurance that EME would be able to recover these increased costs from its customers or that its 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 EME cannot comply with all applicable regulations, it could be required to retire or suspend operations at its facilities, or restrict or modify the operations of its facilities, and its 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. EME cannot provide assurance that it will be able to obtain and comply with all necessary licenses, permits and approvals for its plants. If there is a delay in obtaining required approvals or permits or if EME fails to obtain and comply with such permits, the operation of EME's facilities may be interrupted or become subject to additional costs.

EME's development projects or future acquisitions may not be successful.

EME's future financial condition, results of operation and cash flows will depend in large part upon its ability to successfully implement its long-term strategy, which includes the development and acquisition of electric power generation facilities, with an emphasis on renewable energy (primarily wind and solar), integrated gasification combined cycle, and gas-fired power plants. EME 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 EME's control, such as increased competition, legal and regulatory developments, price volatility in electric or fuel markets, and general economic conditions.

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

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 to apply to new wind projects placed in service by December 31, 2008. If the deadline for production tax credits is not extended again, EME's development activities related to wind projects slated for completion after December 31, 2008 could be adversely affected.

EME's development activities are subject to risks including, without limitation, risks related to project siting, financing, construction, permitting, governmental approvals and the negotiation of project agreements. EME may not be successful in developing new projects or the timing of such development may be delayed beyond the date that turbines are ready for installation. Projects under development may be adversely affected by delays in turbine deliveries or start-up problems related to turbine performance. Furthermore, EME 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 it 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 EME's ability to obtain financing for new projects or the terms and conditions of future financings. If a project under development is abandoned, EME would expense all capitalized costs incurred in connection with that project, and could incur additional losses associated with any related contingent liabilities. If EME is not successful in developing new projects, it may be required to sell turbines that were purchased and such sales may result in substantial losses. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies—Purchase Obligations."

Finally, EME cannot provide assurance that its 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 EME will ultimately realize a satisfactory rate of return.

A substantial portion of wind turbines purchased by EME may not perform as expected during start-up or operations, thereby adversely affecting the expected return on investment.

EME has purchased a significant number of wind turbines in support of its renewable energy activities. The turbines of one turbine manufacturer have experienced rotor blade cracks, and another turbine manufacturer has suspended operations at one site in order to address potential rotor blade and gearbox problems. EME cannot provide assurance that repairs or replacements of the affected turbines will be timely or effective or that expected performance levels will be achieved. Significant delays in project construction could subject projects to damages under their power purchase agreements. The turbine suppliers have provided warranties for workmanship, schedule guarantees and performance guarantees during the first five years after a turbine has been commissioned. However, EME cannot predict at this time the amount of damages that will be received by EME from the turbine suppliers. Furthermore, limited data is presently available regarding the performance of new wind turbines of a size over 2 MW over an extended period of time. Accordingly, EME cannot provide assurance that it will earn its expected return over the life of the projects. For further discussion, see "Item 7. Management's

Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures—Wind Turbine Performance Issues."

Competition could adversely affect EME's 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 EME. 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 EME's ability to compete effectively in the markets in which those entities operate.

Newer plants owned by EME's competitors are often more efficient than EME's facilities. This may put some of EME's facilities at a competitive disadvantage to the extent that its competitors are able to produce more power from each increment of fuel than EME's facilities are capable of producing. Over time, some of EME's 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 EME presently operates or may consider operating in the future, EME is 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 EPAct 2005 and other regulatory initiatives may result in changes in the power industry to which EME may not be able to respond in as timely and effective manner as its competitors.

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

The factors that influence EME's ability to arrange for financing and its costs of capital include:

- general economic and capital market conditions;
- the availability of bank credit and access to capital markets;
- investor confidence;
- the financial condition, performance, prospects, and credit rating of EME 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. EME cannot provide assurance that its projected sources of capital will be available when needed or that its actual cash requirements will not be greater than expected.

EME and its subsidiaries have a substantial amount of indebtedness, including long-term lease obligations.

As of December 31, 2007, EME's consolidated debt was $3.8 billion. In addition, EME's subsidiaries have $3.9 billion of long-term power plant lease obligations that are due over a period ranging up to

27 years. The substantial amount of consolidated debt and financial obligations presents the risk that EME and its subsidiaries might not have sufficient cash to service their indebtedness or long-term lease obligations and that the existing corporate debt, project debt and lease obligations could limit the ability of EME and its subsidiaries to grow their business, to compete effectively, to operate successfully under adverse economic conditions, or to plan for and react to business and industry changes. If EME's or a subsidiary's cash flows and capital resources were insufficient to allow it to make scheduled payments on its debt, EME or its subsidiaries might have to reduce or delay capital expenditures, sell assets, seek additional capital, or restructure or refinance the debt. The terms of EME's or its 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, EME's 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.

Restrictions in the instruments governing EME's indebtedness and the indebtedness of its subsidiaries limit EME's and its subsidiaries' ability to enter into specified transactions that EME or they otherwise may enter into.

The instruments governing EME's indebtedness and the indebtedness of its subsidiaries contain financial and investment covenants. Restrictions contained in these documents or documents EME or its subsidiaries enter in the future could affect, and in some cases significantly limit or prohibit, EME's ability and the ability of its 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 EME's ability and the ability of its subsidiaries to take advantage of business opportunities as they arise, to grow its business or to compete effectively. In addition, these restrictions may significantly impede the ability of EME's subsidiaries to make distributions to EME.

EME's projects may be affected by general operating risks and hazards customary in the power generation industry. EME 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, efficiency or availability;
- 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 EME's projects or significantly increase the costs of operating them, and could also result in EME 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, guarantees, 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 EME's obligations as they become due and could have a material adverse effect on EME. A default under a financing obligation of a project entity could result in a loss of EME's interest in the project.

The accounting for EME's hedging and proprietary trading activities may increase the volatility of its quarterly and annual financial results.

EME engages in hedging activities in order to mitigate its exposure to market risk with respect to electricity sales from its generation facilities, fuel utilized by those facilities and emissions allowances. EME generally attempts to balance its 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. EME also uses derivative contracts with respect to its limited proprietary trading activities, through which EME attempts to achieve incremental returns by transacting where it has specific market expertise. These derivative contracts are recorded on its 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, EME's financial results, including gross margin, operating income and balance sheet ratios, will at times be volatile and subject to fluctuations in value primarily due to changes in electricity and fuel prices. For a more detailed discussion of the accounting treatment of EME's hedging and proprietary trading activities, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures—Accounting for Energy Contracts."

ITEM 1B. UNRESOLVED STAFF COMMENTS

Inapplicable.

ITEM 2. PROPERTIES

EME leases its principal office in Irvine, California. The office lease is for approximately 79,000 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 December 31, 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.

Description of Properties

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

ITEM 3. LEGAL PROCEEDINGS

FERC Notice Regarding Investigatory Proceeding against EMMT

In 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 EPAct 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. Discussions to date have been constructive and may lead to a settlement agreement acceptable to both parties. Should these discussions not result in a settlement and a formal proceeding 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 in the bidding practices that it employed, and intends to contest vigorously any allegation of violation.

Midwest Generation Potential Environmental Proceeding

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990's and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement 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 CAA, 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 CAA. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. As a result, Midwest Generation is investigating the claims made by the US EPA in the NOV and has identified several defenses which it will raise if the government files suit. At this early stage in the process, Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations or financial position.

On August 13, 2007, Midwest Generation and Commonwealth Edison received a letter signed by several Chicago-based environmental action groups stating that, in light of the NOV, the groups are examining the possibility of filing a citizen suit against Midwest Generation and Commonwealth Edison based presumably on the same or similar theories advanced by the US EPA in the NOV.

By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. Midwest Generation and Commonwealth Edison are cooperating with one another in responding to the NOV.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Inapplicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

All the outstanding common stock of EME is, as of the date hereof, owned by MEHC, which is a wholly owned subsidiary of Edison Mission Group Inc., a wholly owned subsidiary of Edison International. There is no market for the common stock. Dividends on the common stock will be paid when declared by EME's board of directors. EME made cash dividend payments totaling $925 million in 2007, $51 million in 2006 and $360 million in 2005. Dividends from EME may be limited based on its earning and cash flow, terms of restrictions contained in EME's corporate credit facility, business and tax considerations, and restrictions imposed by applicable law. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Dividend Restrictions in Major Financings" for more information about dividend restrictions in EME's corporate credit facility.

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data was derived from EME's audited financial statements and is qualified in its entirety by the more detailed information and financial statements, including notes to these financial statements, included in this annual report. EME's international operations are accounted for as discontinued operations, except the Doga project in Turkey. 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 ownership of such projects for all periods presented.

	Years Ended December 31,				
	2007	2006	2005	2004	2003
			(in millions)		
INCOME STATEMENT DATA					
Operating revenues	$ 2,580	$ 2,239	$ 2,265	$ 1,653	$ 1,779
Operating expenses					
Fuel, plant operations and plant operating lease	1,444	1,332	1,287	1,300	1,334
Loss on lease termination, asset impairment and other charges and credits(1)	1	—	7	989	304
Depreciation and amortization	162	144	134	152	156
Administrative and general	209	140	154	149	138
	1,816	1,616	1,582	2,590	1,932
Operating income (loss)	764	623	683	(937)	(153)
Equity in income from unconsolidated affiliates	200	186	229	218	239
Impairment loss on equity method investment	—	—	(55)	—	—
Interest and other income	103	120	69	52	2
Interest expense	(273)	(279)	(300)	(298)	(303)
Loss on early extinguishment of debt	(160)	(146)	(4)	—	—
Income (loss) from continuing operations before income taxes and minority interest	634	504	622	(965)	(215)
Provision (benefit) for income taxes	219	189	208	(406)	(121)
Minority interest	1	1	—	(1)	(2)
Income (loss) from continuing operations	416	316	414	(560)	(96)
Income (loss) from operations of discontinued subsidiaries (including gain on disposal of $533 million in 2004), net of tax	(2)	98	29	690	124
Income before accounting change	414	414	443	130	28
Cumulative effect of change in accounting, net of tax(2)	—	—	(1)	—	(9)
Net income	$ 414	$ 414	$ 442	$ 130	$ 19

(1) During 2004, EME recorded loss on lease termination, asset impairment and other charges primarily related to the loss on termination of the lease related to the Collins Station and the return of its ownership to EME. During 2003, EME recorded asset impairment charges primarily related to the write-down of the carrying amount of all eight small peaking units in Illinois to their estimated fair value.

(2) The 2005 loss from a change in accounting principle resulted from the adoption of a new accounting standard for conditional asset retirements. The 2003 loss from a change in accounting principle resulted from adoption of a new accounting standard for AROs.

	As of December 31,				
	2007	**2006**	**2005**	**2004(3)**	**2003(4)**
			(in millions)		
BALANCE SHEET DATA					
Assets	$ 7,308	$ 7,250	$ 7,023	$ 7,087	$ 12,299
Current liabilities	475	646	846	994	1,203
Long-term obligations	3,806	3,035	3,330	3,530	2,919
Shareholder's equity	1,923	2,582	1,910	1,745	1,954

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

(4) In the fourth quarter of 2003, EME adopted FIN No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51," which required EME 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.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This MD&A contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements reflect EME's current expectations and projections about future events based on EME's knowledge of present facts and circumstances and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by EME that is incorporated in this MD&A, or that refers to or incorporates this MD&A, may also contain forward-looking statements. In this MD&A 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. See "Item 1. Business—Forward-Looking Statements" and "Item 1A. Risk Factors" for a discussion of some of the risks, uncertainties and other important factors that could cause results to differ, or otherwise could impact EME or its subsidiaries. Additional information about risks and uncertainties is contained throughout this MD&A. Readers are urged to read this entire annual report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect EME's business. Forward-looking statements speak only as of the date they are made and EME is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by EME with the Securities and Exchange Commission.

This MD&A 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 December 31, 2007, EME's subsidiaries and affiliates owned or leased interests in 28 operating projects and 8 wind 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 as a holding company. In this regard, EME has borrowed funds to make equity contributions required for its projects and for general corporate purposes. Since EME as a holding company does not 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.

Significant Industry and EME Developments

Renewable Energy

New generation from renewable energy, including wind, has grown significantly in the United States due to improved technology, higher fossil fuel prices, emphasis on reducing emissions and federal and state programs that provide incentives, including production and investment tax credits. In January 2008, the American Wind Energy Association announced that the U.S. wind energy industry had installed 5,244 MW in 2007, expanding the nation's total wind power generating capacity by 45%. According to this report, new wind projects accounted for about 30% of the total new installation of power-producing capacity in the U.S. during 2007.

EME has expanded its business development activities in order to grow and diversify its existing portfolio of power projects, including renewable energy projects. Most of EME's near-term development and investment activity is in wind power. At December 31, 2007, EME had 566 MW of wind projects in service and another 447 MW of wind projects under construction, with scheduled completion dates during 2008. At December 31, 2007, EME had a development pipeline of potential wind projects with an estimated installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. This development pipeline is supported by turbine purchase commitments of 1,166 MW for new wind projects. The majority of the turbines are scheduled to be delivered before the end of 2009. See "Liquidity and Capital Resources—Business Development" for details of activities during 2007.

Environmental Regulations Affecting Coal Plants

Federal environmental regulations currently require power plants to reduce emissions during 2009 and require states to adopt implementation plans that are equal to or more stringent than the federal requirements. Compliance with these regulations and SIPs could require substantial additional capital expenditures or closure of coal-fired power plants. In advance of the federal requirements, Midwest Generation entered into an agreement with the Illinois EPA on December 11, 2006, to reduce mercury, NO_X and SO_2 emissions at Midwest Generation's Illinois coal-fired power plants, which Midwest Generation believes provides 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. During 2007, EME commenced activities to install activated carbon injection technology to reduce mercury emissions at the Illinois Plants and the Homer City facilities. EME Homer City will be subject to the federal CAIR rule during 2009 and expects to be able to comply with the NO_X requirement using its existing SCR system. The Pennsylvania CAIR, including both NO_X and SO_2 limits, is expected to become effective in 2010, at which time EME Homer City expects to purchase SO_2 allowances. See "Liquidity and Capital Resources—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Interstate Rule" for further discussion.

The U.S. Congressional leadership has made climate change legislation a priority, and enactment of climate change legislation within the next several years may occur. While debate continues at the national level over domestic climate policy and the appropriate scope and terms of any federal legislation, many states are developing state-specific measures or participating in regional legislative initiatives to reduce GHG emissions. State regulations may vary and may be more stringent and costly than federal legislative proposals currently being debated in Congress. Key uncertainties are whether a cap-and-trade program will be implemented similar to the US EPA acid rain program, and, if implemented, whether emission allowances would be provided to impacted parties without cost for a period of time. Furthermore, the rate of decrease in GHG emissions and the cost to purchase allowances would be significant factors in determining whether environmental controls would be economic to install. The potential impact to power generators, like EME, will depend upon how these factors and many other considerations are resolved.

Regulatory Developments on New Capacity

In NERC's 2007 Long-Term Reliability Assessment (2007-2016), the forecasted peak demand of electricity in certain regions of the United States will exceed projected committed resources in such regions, resulting in declining reserve margins for capacity. Additional resources that are not currently committed will be needed to maintain system reliability. In PJM, long-term resource planning has been incorporated into its market structure through a new forward capacity market, referred to as RPM. During 2007 and January 2008, PJM completed capacity auctions under the PJM RPM for periods through May 31, 2011. EME participated in each auction, which sold forward significant capacity at prices from $40.80 per MW-day to $191.32 per MW-day. The increase in capacity prices determined through the PJM RPM reflects the auction design to encourage increased capacity resources to meet projected demand. As a result of these auctions, EME expects capacity revenues to increase significantly through May 31, 2011 as compared to the amounts realized by EME previously. For further discussion regarding the PJM and recent auctions, see "Market Risk Exposures—Commodity Price Risk—Capacity Price Risk."

Increase in Equipment and Construction Costs

During the past several years, the cost to build new generation has risen significantly. In September 2007, the Brattle Group prepared a report for the Edison Foundation (unaffiliated with Edison International) that identified four primary sources of the increase in construction costs: (1) material input costs, (2) shop and fabrication capacity, (3) cost of construction field labor, and (4) the market for large construction project management. Increases in costs can be partially mitigated to the extent that equipment has been procured, as in the case of the wind turbines discussed above. However, for projects in development to be economically viable, higher capital costs will need to be reflected in higher power prices in power purchase agreements, or in higher forward prices for wholesale energy and capacity and/or renewable energy credits. The above factors may also increase the cost of constructing the environmental controls needed to reduce emissions. See "Liquidity and Capital Resources—Capital Expenditures" and "Liquidity and Capital Resources—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Interstate Rule—Illinois" for a more detailed discussion.

Financing Activities

Senior Notes

In May 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 used the net proceeds, together with cash on hand, to repay debt 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. In June 2007, MEHC redeemed in full its senior secured notes. In connection with the purchase of these notes, EME recorded a total pre-tax loss of approximately $160 million (approximately $98 million after tax) on early extinguishment of debt in 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. Midwest Generation uses its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation can also support its hedging activities by granting 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 ERP application from SAP during the following 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. Procurement and material management systems were implemented for three of the Illinois Plants on July 2, 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 a fuel management system began on October 1, 2007. EME plans to implement the human resources systems during the first half of 2008 as part of an Edison International enterprise-wide project.

Net Income Summary

Net income is comprised of the following components:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Income from continuing operations	$ 416	$ 316	$ 414
Income (loss) from discontinued operations	(2)	98	29
Cumulative changes in accounting principle	—	—	(1)
Net Income	$ 414	$ 414	$ 442

EME's 2007 increase in income from continuing operations was primarily due to higher operating income at the Illinois Plants and Homer City facilities and higher energy trading income, partially offset by higher development and other corporate costs. EME's 2007 and 2006 income from continuing operations included a $98 million and $90 million, respectively, loss on early extinguishment of debt.

EME's 2006 decrease in income from continuing operations was primarily due to loss on early extinguishment of debt, lower generation at the Illinois Plants and lower energy trading income. Partially offsetting these decreases were a favorable change in SFAS No. 133 unrealized gains, lower net interest expense and the March Point impairment loss recorded during 2005.

EME's 2006 and 2005 income from discontinued operations, net of tax, was primarily related to distributions authorized by the liquidators of the Lakeland power project. EME has received a total of $125 million and $24 million of distributions in 2006 and 2005, respectively, from the settlement of a 2001 claim for termination of a power contract by a subsidiary of TXU Europe Group plc. The activities of the Lakeland liquidator are near completion and substantially all the distributions from the Lakeland project have been made.

See "Results of Operations" for further discussion of EME's operating results.

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 SFAS No. 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. The remaining gain or loss on the derivative instrument, if any, is recognized currently 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, 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.

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, EME recorded impairment charges of $55 million related to specific assets included in continuing operations. See "Results of Operations—Results of Continuing Operations—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—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 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 December 31, 2007, EME had recorded an estimated liability of $101 million related to these matters.

In addition, 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 a supplemental agreement. See "Liquidity and Capital Resources—Contractual Obligations, Commitments and Contingencies—Commercial Commitments." Midwest Generation engaged an independent actuary during 2007 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 2044. At December 31, 2007, Midwest Generation had recorded a liability of $54 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. FIN No. 48 clarifies the accounting for uncertain tax positions. FIN No. 48 (adopted on January 1, 2007) 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. Management continues to monitor and assess new income tax developments. See "Edison Mission Energy and Subsidiaries 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 accrued liabilities or other long-term liabilities in the consolidated balance sheet. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. Management uses judgment in determination of whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit.

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

RESULTS OF OPERATIONS

Introduction

This section discusses operating results in 2007, 2006 and 2005. Continuing operations primarily include EME's Illinois Plants and Homer City facilities, energy trading, gas-fired and wind-powered projects under contract, corporate interest expense and general and administrative expenses. Discontinued operations include all of EME's international operations, except the Doga project. This section also discusses the effect of new accounting pronouncements on EME's consolidated financial statements.

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.

This section is organized under the following headings:

Results of Continuing Operations

Overview

EME operates in one line of business, independent power production. Operating revenues are primarily derived from the sale of energy and capacity 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. 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.

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

The following section provides a summary of the operating results for the three years ended December 31, 2007 together with discussions of the contributions by specific projects and of other significant factors affecting these results.

	Years Ended December 31		
	2007	2006	2005
		(in millions)	
Project Earnings (Losses) Before Income Taxes(1)			
Consolidated operations			
Illinois Plants	$ 658	$ 459	$ 547
Homer City	226	156	74
Energy Trading(2)	143	130	195
San Juan Mesa	6	7	—
Gain on sale of assets	—	4	—
Minnesota Wind projects	6	1	2
Storm Lake	5	5	2
Wildorado	11	—	—
Other	6	(1)	(3)
Unconsolidated affiliates			
Big 4 projects	146	132	158
Sunrise	33	34	29
March Point	—	—	9
Impairment loss on equity method investment	—	—	(55)
Doga	14	1	7
Other	12	12	13
	1,266	940	978
Corporate interest income	73	82	55
Corporate interest expense	(331)	(253)	(270)
Corporate administrative and general	(175)	(113)	(126)
Loss on early extinguishment of debt	(160)	(146)	(4)
Other income (expense), net	(10)	10	(3)
	$ 663	$ 520	$ 630

(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 $26 million, $13 million and $4 million for the years ended December 31, 2007, 2006 and 2005, respectively. The project earnings for the wind projects include $29 million, $16 million and $8 million of production tax credits for the years ended December 31, 2007, 2006 and 2005, 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,		
	2007	2006	2005
		(in millions)	
Project earnings	$ 663	$ 520	$ 630
Less: Production tax credits	(29)	(16)	(8)
Income from continuing operations before income taxes and minority interest	$ 634	$ 504	$ 622

(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

	Years Ended December 31		
	2007	**2006**	**2005**
		(in millions)	
Operating Revenues	$ 1,579	$ 1,399	$ 1,429
Operating Expenses			
Fuel(1)	400	382	383
Gain on sale of emission allowances(2)	(18)	(16)	(56)
Plant operations	420	369	351
Plant operating leases	75	75	75
Depreciation and amortization	99	101	99
Loss (gain) from disposal of assets	—	4	7
Administrative and general	22	19	19
Total operating expenses	998	934	878
Operating Income	581	465	551
Other Income (Expense)			
Interest income on note receivable from EME	113	113	113
Interest expense and other	(36)	(119)	(117)
Total other income (expense)	77	(6)	(4)
Income Before Taxes	$ 658	$ 459	$ 547
Statistics			
Generation (in GWh):			
Energy only contracts	22,503	28,898	30,953
Load requirements services contracts(3)	7,458	—	—
Total	29,961	28,898	30,953
Aggregate plant performance:			
Equivalent availability(4)	75.8%	79.3%	79.6%
Capacity factor(5)	60.9%	58.8%	63.0%
Load factor(6)	80.4%	74.1%	79.1%
Forced outage rate(7)	9.7%	7.9%	7.8%
Average realized price/MWh:			
Energy only contracts(8)	$ 48.79	$ 46.19	$ 45.55
Load requirements services contracts(9)	$ 63.43	$ —	$ —
Capacity revenue only (in millions)	$ 27	$ 24	$ 27
Average fuel costs/MWh	$ 13.36	$ 13.19	$ 12.40

(1) The Illinois Plants purchased NO_X emission allowances from the Homer City facilities at fair market value. Purchases were $0.4 million in 2007, $6 million in 2006 and $5 million in 2005. 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 $21 million in 2007, $14 million in 2006 and $61 million in 2005. These sales reduced operating expenses. EME eliminated $2 million of intercompany profit during the fourth quarter of 2007 on emission allowances sold but not yet used by the Homer City facilities at December 31, 2007. In addition, EME recorded $4 million of intercompany profit during 2007 that was eliminated by EME in 2006 on emission allowances sold by the Illinois Plants

to the Homer City facilities in the fourth quarter of 2006 but not used by the Homer City facilities until the first quarter of 2007. 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.

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

(4) The equivalent availability factor is defined as the number of MWh 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.

(5) 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.

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

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

(8) 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.

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Operating revenues	$ 1,579	$ 1,399	$ 1,429
Less:			
Load requirements services contracts	(473)	—	—
Unrealized losses (gains)	25	(30)	19
Other revenues	(33)	(34)	(38)
Realized revenues	$ 1,098	$ 1,335	$ 1,410
Generation (in GWh)	22,503	28,898	30,953
Average realized energy price/MWh	$48.79	$46.19	$45.55

(9) 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 $199 million in 2007 compared to 2006, and decreased $88 million in 2006 compared to 2005. The 2007 increase in earnings was primarily attributable to higher energy revenues resulting from higher average realized energy prices and slightly higher generation as compared to 2006 and lower interest expense. Partially offsetting these increases were higher planned maintenance costs, unplanned outages at the Powerton Station and a $7.5 million payment during the third quarter of 2007 related to the settlement agreement with the Illinois Attorney General. Earnings were also adversely affected by an increase in unrealized losses in 2007 related to hedge contracts described below.

On November 2, 2007, Unit 5 at the Powerton Station had an unplanned outage related to a low pressure turbine. The turbine was repaired and the unit was returned to service on December 13, 2007. On December 18, 2007, Unit 6 at the Powerton Station had a duct and fan failure resulting in a suspension of operations at this unit through January 4, 2008 when the unit returned at half-load capability. Scheduled maintenance work for the spring of 2008 was accelerated to minimize the aggregate impact of the outage. Repairs were completed on February 13, 2008 and the unit has been returned to service.

The 2006 decrease in earnings was primarily attributable to lower energy revenues resulting from lower generation, a decrease in sales of excess SO_2 emission allowances in 2006, as compared to 2005, due to lower prices for SO_2 allowances and higher plant overhaul costs. Partially offsetting these decreases was an increase in unrealized gains in 2006 related to hedge contracts described below.

Included in operating revenues were unrealized gains (losses) of $(25) million, $30 million and $(19) million in 2007, 2006 and 2005, 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 December 31, 2007, unrealized losses of $18 million were recognized from economic hedges and from the ineffective portion of cash flow hedges related to subsequent periods. The ineffective portion of hedge contracts at the Illinois Plants was primarily attributable to changes in the difference between energy prices at NiHub (the settlement point under forward contracts) and the energy prices at the Illinois Plants busbars (the delivery point where power generated by the Illinois Plants is delivered into the transmission system) resulting from marginal losses. During 2005, 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. 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 $113 million for each of the years ended December 31, 2007, 2006 and 2005, 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,		
	2007	2006	2005
		(in millions)	
Operating Revenues	$ 764	$ 642	$ 592
Operating Expenses			
Fuel(1)	306	283	288
Gain on sale of emission allowances(2)	—	(7)	(4)
Plant operations	119	106	112
Plant operating leases	102	102	102
Depreciation and amortization	14	16	16
Administrative and general	4	5	6
Total operating expenses	545	505	520
Operating Income	219	137	72
Other Income (Expense)			
Interest and other income	9	20	3
Interest expense	(2)	(1)	(1)
Total other income	7	19	2
Income Before Taxes	$ 226	$ 156	$ 74
Statistics			
Generation (in GWh)	13,649	12,286	13,637
Equivalent availability(3)	89.4%	81.9%	85.2%
Capacity factor (4)	82.5%	74.3%	82.4%
Load factor (5)	92.4%	90.7%	96.7%
Forced outage rate(6)	4.1%	13.5%	4.8%
Average realized energy price/MWh(7)	$ 54.40	$ 48.02	$ 45.05
Capacity revenue only (in millions)	$ 30	$ 16	$ 18
Average fuel costs/MWh	$ 22.45	$ 23.05	$ 21.08

(1) The Homer City facilities purchased SO_2 emission allowances from the Illinois Plants at fair market value. Purchases were \$21 million in 2007, \$14 million in 2006 and \$61 million in 2005. These purchases are included in fuel costs.

(2) The Homer City facilities sold excess NO_X emission allowances to the Illinois Plants at fair market value. Sales to the Illinois Plants were \$0.4 million in 2007, \$6 million in 2006 and \$5 million in 2005. 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 MWh 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 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.

	Years Ended December 31,		
	2007	**2006**	**2005**
		(in millions)	
Operating revenues	$ 764	$ 642	$ 592
Less:			
Unrealized losses (gains)	10	(35)	41
Other revenues	(31)	(17)	(18)
Realized revenues	$ 743	$ 590	$ 615
Generation (in GWh)	13,649	12,286	13,637
Average realized energy price/MWh	$ 54.40	$ 48.02	$ 45.05

Earnings from Homer City increased $70 million in 2007 compared to 2006 and $82 million in 2006 compared to 2005. The 2007 increase was primarily attributable to an increase in energy revenues from higher generation and average realized energy prices, and an increase in capacity revenues resulting from the PJM RPM auction. Partially offsetting these increases were higher maintenance costs in 2007 related to the planned outage at Unit 2 of the Homer City facilities and lower other income in 2007 for the estimated insurance recovery related to the Unit 3 outage of approximately $3 million recorded during the third quarter of 2007, compared to approximately $11 million recorded during the second quarter of 2006, reflected in other income (expense), net in EME's consolidated statements of income. Earnings for 2007 were also adversely affected due to the timing of unrealized gains and losses related to hedge contracts discussed below. Included in fuel costs were $31 million, $35 million and $81 million in 2007, 2006 and 2005, respectively, related to the net cost of SO_2 emission allowances. See "Market Risk Exposures—Commodity Price Risk—Emission Allowances Price Risk" for more information regarding the price of SO_2 allowances.

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 SO_2 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 operating revenues were unrealized gains (losses) from hedge activities of $(10) million, $35 million and $(41) million in 2007, 2006 and 2005, 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, 2007, unrealized losses of $21 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.

The average realized energy price received by Homer City in 2007, 2006 and 2005 was $54.40/MWh, $48.02/MWh and $45.05/MWh, respectively, compared to the average real-time market price at the Homer City busbar for the same periods of $51.03/MWh, $45.15/MWh and $54.80/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, (2) differences between market prices during periods of actual generation (generally weighted to on-peak periods) and the 24-hour average real-time market prices, and (3) 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 the past three years, the basis between these two locations has continued to widen 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. The main transformer failure resulted in claims under Homer City's property and business interruption insurance policies, which have been settled and paid.

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 $143 million, $130 million and $195 million in 2007, 2006 and 2005, respectively. The 2007 increase in earnings from energy trading activities was primarily attributable to increased earnings from financial transmission rights used at specific delivery points in the eastern power grid and higher earnings from energy trading in the over-the-counter markets. 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.

San Juan Mesa

Earnings from the San Juan Mesa wind project were $6 million and $7 million in 2007 and 2006, respectively, with no earnings recorded in 2005 due to the acquisition of the San Juan Mesa wind project on December 27, 2005. Earnings are primarily driven by capacity factors.

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.

Storm Lake

Earnings from the Storm Lake wind project were $5 million, $5 million and $2 million in 2007, 2006 and 2005, respectively. Earnings are primarily driven by capacity factors, which were about the same in each year.

Minnesota Wind Projects

Earnings from the Minnesota wind projects increased $5 million in 2007 from 2006 and decreased $1 million in 2006 from 2005. The 2007 increase was primarily due to receipt of availability payments from the turbine supplier and lower interest expense in 2007.

Wildorado

Earnings from the Wildorado wind project were $11 million in 2007. EME had no comparable results from the Wildorado wind project in 2006. Commercial operation of the Wildorado wind project commenced during April 2007.

Other

Earnings from other consolidated operations increased $7 million in 2007 compared to 2006, and $2 million in 2006 compared to 2005. The 2007 increase was primarily attributable to the improvement in the performance of EME's gas transportation agreement resulting from increased gas supply in the Rocky Mountain region which increased the market price of gas transportation into California.

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 increased $14 million in 2007 compared to 2006, and decreased $26 million in 2006 compared to 2005. The 2007 change in earnings was primarily due to payments received in settlement of claims related to the natural gas purchase contracts during the second quarter of 2007 and outages at the Sycamore Cogeneration plant in 2006. Partially offsetting these increases were lower volumes sold in 2007 for the Kern River project.

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 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.

Earnings from the Big 4 projects are net of interest expense of $2 million, $5 million and $9 million in 2007, 2006 and 2005, respectively, with respect to Edison Mission Energy Funding.

Two of the Big 4 projects (the Sycamore project and the Watson project) are currently selling electricity to SCE under terms and conditions contained in their prior long-term power purchase agreements with revised pricing terms as mandated by the California Public Utilities Commission. Due to the lower pricing, EME expects that pre-tax earnings from the Watson and Sycamore projects in the aggregate will decrease by $80 million to $90 million during 2008.

Sunrise

Earnings from the Sunrise project decreased $1 million in 2007 from 2006 and increased $5 million in 2006 from 2005. The 2007 decrease was primarily due to lower availability incentive payments partially offset by lower interest expense in 2007. The 2006 increase was largely due to higher capacity revenues and availability incentive payments in 2006.

March Point

Earnings from March Point were $9 million in 2005 with no earnings recorded in 2006 and 2007 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 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. Effective March 31, 2007, EME accounted for its ownership in the Doga project on the cost method (earnings are recognized when cash is distributed from the project).

Earnings from the Doga project increased $13 million in 2007 compared to 2006 and decreased $6 million in 2006 compared to 2005. The 2007 increase was primarily due to the recognition of distributions received from the Doga project. The 2006 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 decreased $9 million in 2007 from 2006 and increased $27 million in 2006 from 2005. The 2007 decrease was primarily attributable to lower average cash balances in 2007 compared to 2006. The 2006 increase was primarily attributable to higher interest rates in 2006 compared to 2005.

Corporate Interest Expense

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Interest expense to third parties	$ 216	$ 138	$ 157
Interest expense to Midwest Generation(1)	115	115	113
Total corporate interest expense	$ 331	$ 253	$ 270

(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, before capitalized interest, increased $94 million in 2007, compared to 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, a portion of which was used to repay $1.3 billion of indebtedness of Midwest Generation (thereby reducing interest expense of Midwest Generation by $71 million). Capitalized interest increased $16 million in 2007 compared to 2006, due to wind projects under construction.

Corporate Administrative and General Expenses

Administrative and general expenses increased $62 million in 2007 from 2006, and decreased $13 million in 2006 from 2005. The 2007 increase was primarily due to higher development costs incurred in 2007 (mostly related to wind projects), higher corporate expenses and a loss accrual related to legal proceedings recorded in the third quarter of 2007. 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.

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt was $160 million in 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 $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 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 decreased $20 million in 2007 from 2006 and increased $13 million in 2006 from 2005. The 2007 decrease was partially attributable to higher corporate depreciation expense incurred in 2007 and 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 $219 million in 2007, $189 million in 2006 and $208 million in 2005. 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 $29 million, $16 million and $8 million of production tax credits related to wind projects for the years ended December 31, 2007, 2006 and 2005, respectively, and $10 million, $14 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.

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). For further discussion of FIN 47 see "Asset Retirement Obligations" in Note 7 of "Item 8. Financial Statements and Supplementary Data—Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements." EME recorded a $1 million, after tax, decrease to net income as the cumulative effect of the adoption of FIN 47.

Results of Discontinued Operations

Income (loss) from discontinued operations, net of tax, was $(2) million in 2007, $98 million in 2006 and $29 million in 2005. The 2007 decrease was largely attributable to distributions received from the Lakeland project, discussed below.

The 2006 increase was largely attributable to distributions received from the Lakeland project. 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.

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 £5 million (approximately $10 million) in 2007. The after-tax income attributable to the Lakeland project was $6 million, $85 million and $24 million for 2007, 2006 and 2005, 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).

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 $747 million, $756 million and $932 million in 2007, 2006 and 2005, respectively.

New Accounting Pronouncements

Accounting Principles Adopted

Statement of Financial Accounting Standards Interpretation No. 48

In July 2006, the FASB issued 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 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 year ended December 31, 2007.

Accounting Principles Not Yet Adopted

FASB Staff Position FIN No. 39-1

In April 2007, the FASB issued FIN No. 39-1. 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 in the first quarter of 2008. The adoption is expected to 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.

Statement of Financial Accounting Standards No. 159

In February 2007, the FASB issued 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. EME will adopt this pronouncement in the first quarter of 2008. Since EME elected not to report any current financial assets and liabilities at fair value, the adoption will not result in any cumulative-effect adjustment to retained earnings.

Statement of Financial Accounting Standards No. 157

In September 2006, the FASB issued 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 in the first quarter of 2008. The adoption is not expected to result in any retrospective adjustment to its consolidated financial statements. The accounting requirements for employers' pension and other postretirement benefit plans is effective at the end of 2008, which is the next measurement date for these benefit plans. The effective date will be January 1, 2009 for asset retirement obligations and other nonfinancial liabilities which are not measured or disclosed on a recurring basis (at least annually).

Statement of Financial Accounting Standards No. 141(R)

In December 2007, the FASB issued SFAS No. 141(R), which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS No. 141(R) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after fiscal years beginning January 1, 2009. Early adoption is not permitted.

Statement of Financial Accounting Standards No. 160

In December 2007, the FASB issued SFAS No. 160, which requires an entity to clearly identify and present ownership interests in subsidiaries held by parties other than the entity in the consolidated financial statements within the equity section but separate from the entity's equity. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interest be accounted for similarly as equity transactions; and when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary be measured at fair value. EME will adopt SFAS No. 160 on January 1, 2009. In accordance with this standard, EME will reclassify minority interest to a component of shareholder's equity (at December 31, 2007 this amount was $42 million).

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of liquidity and capital resources is organized in the following sections:

EME's Liquidity

At December 31, 2007, EME and its subsidiaries had cash and cash equivalents and short-term investments of $1.1 billion, EME had a total of $507 million of available borrowing capacity under its $600 million corporate credit facility, and Midwest Generation had a total of $497 million of available borrowing capacity under its $500 million working capital facility. EME's consolidated debt at December 31, 2007 was $3.8 billion. In addition, EME's subsidiaries had $3.9 billion of long-term lease obligations related to sale-leaseback transactions that are due over periods ranging up to 27 years.

EME Financing Developments

Senior Notes

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 pays interest on the senior notes on May 15 and November 15 of each year, beginning on November 15, 2007. On October 22, 2007, EME commenced an exchange offer to exchange the senior notes for an equal principal amount of senior notes which have been registered under the Securities Act. 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.

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 $160 million ($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, 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 U.S. Securities and Exchange Commission.

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 uses its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation can also support its hedging activities by granting liens to eligible hedge counterparties.

Business Development

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

- Acquired and/or completed development and commenced construction with completion scheduled for 2008 of seven new wind projects, including:
  - the 61 MW Mountain Wind I project and the 80 MW Mountain Wind II project, both located in Wyoming,
  - the 38 MW Lookout wind project and the 29 MW Forward wind project, both located in Pennsylvania,
  - the 20 MW Odin wind project located in Minnesota,
  - the 19 MW Spanish Fork wind project located in Utah, and
  - the 150 MW Goat Mountain wind project located in Texas.

  The combined estimated capital cost of these projects, excluding capitalized interest, is expected to be approximately $700 million. EME owns 100% of each of these projects, except for the Odin and Goat Mountain wind projects, in which EME owns 99.9%. 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(s) or as a merchant wind generator.

- Completed construction and commenced operations of the 161 MW Wildorado wind project located in Texas in April 2007, the 15 MW Hardin wind project located in Iowa in May 2007, the 21 MW Crosswinds wind project also located in Iowa in June 2007, and the 95 MW Sleeping Bear wind project located in Oklahoma in October 2007.

- 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 and beyond. 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 the 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 October 2007, EME acquired an option to acquire 100% interests in two wind energy projects under development in Nevada. The projects are in development with target completion dates of 2010 and beyond. 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 the 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 December 2007, EME entered into a joint development agreement to develop jointly a portfolio of projects (approximately 2,350 MW) located in Arizona, Nevada and New Mexico. Pursuant to the joint development agreement, EME paid $24 million to acquire a 1% interest in twelve designated projects and the option to purchase the remaining 99%. The projects are in development with target completion dates generally beyond 2008. EME is required to fund ongoing development expenses for each project. 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 the individual projects, partially offset by up to $3.4 million per year as a result of the payment of the purchase option. 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.

Capital Expenditures

At December 31, 2007, the estimated capital expenditures through 2010 by EME's subsidiaries related to existing projects, corporate activities and turbine commitments were as follows:

	2008	2009	2010
		(in millions)	
Illinois Plants			
Plant capital expenditures	$ 63	$ 71	$ 42
Environmental expenditures	46	57	246
Homer City Facilities			
Plant capital expenditures	35	34	26
Environmental expenditures	18	9	9
Wind Projects			
Projects under construction	195	4	—
Turbine commitments	484	540	49
Corporate capital expenditures	20	14	8
Total	$ 861	$ 729	$ 380

Expenditures for Existing Projects

Plant capital expenditures relate to non-environmental projects such as upgrades to boiler and turbine controls, railroad interconnection, replacement of major boiler components, mill inerting projects and ash site disposal development. Environmental expenditures relate to environmental projects such as mercury emission monitoring and control and a selenium removal system 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 fund these expenditures with debt 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—Significant Industry and EME Developments—Environmental Regulations Affecting Coal Plants," "Management's Overview—Significant Industry and EME Developments—Increase in Equipment and Construction Costs," "—Environmental Matters and Regulations—Air Quality Regulation—Clean Air Interstate Rule—Illinois," and "—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 several years. At December 31, 2007, EME had committed to purchase turbines (as reflected in the above table of capital expenditures) for wind projects that aggregate 1,166 MW. The turbine commitments generally represent approximately two-thirds of the total capital costs of EME's wind projects. As of December 31, 2007, EME had a development pipeline of potential wind projects with projected installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. Completion of development of a wind project may take a number of years due to factors that include local permit requirements, willingness of local utilities to purchase renewable power at sufficient prices to earn an appropriate rate of return, and availability and prices of equipment. Furthermore, successful completion of a wind project is dependent upon obtaining permits, an interconnection agreement(s) or other agreements necessary to support an investment. There is no assurance that each project included in the development pipeline currently or added in the future will be successfully completed.

On February 13, 2008, President Bush signed the Economic Stimulus Act of 2008 which includes a provision for accelerated bonus depreciation for certain capital expenditures acquired and placed in service during 2008. EME expects a portion of its capital expenditures made in 2008 will qualify for this accelerated bonus depreciation which will reduce tax payments for 2008.

Wind Turbine Performance Issues

EME has purchased a significant number of wind turbines in support of its renewable energy activities. The purchases include 475 of 2.1 MW Model S88 wind turbines manufactured by Suzlon Wind Energy Corporation (Suzlon) and 71 of 2.5 MW Model C96 wind turbines manufactured by Clipper Turbine Works, Inc. (Clipper). These turbines are designed to, among other things, improve a project's economics by increasing the size of an individual unit. The turbine suppliers have provided warranties for workmanship, schedule guarantees and performance guarantees during the first five years after a turbine has been commissioned.

After commissioning EME's Sleeping Bear, Hardin and Crosswinds projects, EME and Suzlon identified rotor blade cracks on certain of the Suzlon Model S88 wind turbines at these sites. Suzlon is discussing with EME a remediation plan for these blades, which is expected to include repairing or replacing all Model S88 blades at these projects. Further analysis and testing is required to determine whether the remediation plan will correct the current deficiencies. A delay in completing remediation may adversely affect operating performance of these projects, may delay completion of projects under construction and may subject such projects to damages under the projects' power purchase agreements. Pursuant to the turbine supply contracts with Suzlon, EME expects Suzlon to pay for certain unavailability damages and/or delay damages.

EME purchased Clipper Model C96 wind turbines for its Jeffers project. During the pre-commissioning phase, Clipper has advised EME to suspend operating the wind turbines at the Jeffers project as a result of rotor blade and gearbox problems experienced at another non-EME wind farm operating with similar Clipper turbines. Clipper has conducted a root cause analysis of these problems, and is in the process of implementing a remediation plan at the Jeffers project to repair and/or replace the affected blades and gearboxes pursuant to its warranty obligations. Delays attributable to the remediation have also delayed completion of the Jeffers project and may subject it to damages under the project's power purchase agreement. Pursuant to the warranty contracts with Clipper, EME expects Clipper to pay certain unavailability damages and/or delay damages.

Although the vendors expect that these efforts will be successful, there is no assurance that repairs will be effective and that expected performance will be achieved. Accordingly, there is no assurance that EME will earn its expected return over the life of the affected projects.

EME's Historical Consolidated Cash Flow

Consolidated Cash Flows from Operating Activities

Net cash provided by (used in) operating activities:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Continuing operations	$ 519	$ 1,131	$ (239)
Discontinued operations	(2)	94	20
	$ 517	$ 1,225	$ (219)

The 2007 decrease in cash provided by operating activities from continuing operations was primarily attributable to an increase of $48 million in required margin and collateral deposits in 2007 for EME's hedging and trading activities, compared to a decrease of $625 million in 2006. This change resulted from an increase in forward market prices in 2007 from 2006. The decrease was also due to timing of cash receipts and disbursements related to working capital items. Partially offsetting these decreases was higher pre-tax income from continuing operations in 2007 compared to 2006.

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.

Cash provided by operating activities from discontinued operations decreased in 2007 from 2006 and increased in 2006 from 2005 reflecting higher distributions received in 2006 compared to 2007 and 2005 from the Lakeland power project. See "Results of Operations—Results of Discontinued Operations—Lakeland Project" for more information regarding these distributions.

Consolidated Cash Flows from Financing Activities

Net cash used in financing activities:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Continuing operations	$ (417)	$ (461)	$ (773)

The 2007 decrease in cash used in financing activities from continuing operations was primarily attributable to net proceeds of $2.7 billion received from EME's issuance of senior notes in 2007, 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 addition, EME received a cash contribution of $36 million in 2007 from MEHC. Partially offsetting the decrease were dividend payments made to MEHC of $925 million in 2007 compared to $51 million in 2006. In 2006, net proceeds of $1 billion were received from EME's issuance of senior notes, which were mostly used to repay $1 billion of EME's outstanding senior notes. Tender premiums and related fees paid associated with the foregoing financings were $137 million and $139 million in 2007 and 2006, respectively.

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.

Consolidated Cash Flows from Investing Activities

Net cash used in investing activities:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Continuing operations	$ (319)	$ (706)	$ (134)
Discontinued operations	—	—	5
	$ (319)	$ (706)	$ (129)

The 2007 decrease in cash used in investing activities from continuing operations was primarily due to net maturities and sales of marketable securities of $477 million in 2007, compared to net purchases of marketable securities of $375 million in 2006. Mostly offsetting this decrease was higher capital expenditures and turbine deposits (net of deposit refunds of $112 million) in 2007, compared to 2006, largely related to the wind projects. 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. During 2007, EME paid $22 million towards the purchase price of new wind projects, and $24 million to acquire a 1% interest in twelve designated projects and the option to purchase the remaining 99%. 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.

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.

Credit Ratings

Overview

Credit ratings for EME, Midwest Generation and EMMT, at December 31, 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 S&P or 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 December 31, 2007, EMMT had deposited $83 million in cash with brokers in margin accounts in support of futures contracts and had deposited $38 million with counterparties in support of forward energy and transmission contracts. In addition, EME had issued letters of credit of $30 million in support of commodity contracts at December 31, 2007.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2007, if wholesale energy prices increase or the amount hedged increases. EME estimates that margin and collateral requirements for energy contracts outstanding as of December 31, 2007 could increase by approximately $310 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 December 31, 2007, Midwest Generation had available $497 million of borrowing capacity under this credit facility. As of December 31, 2007, Midwest Generation had $54 million in loans receivable from EMMT for margin advances. In addition, EME has cash on hand and $507 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 December 31, 2007, EME had corporate cash and cash equivalents and short-term investments of $846 million to meet liquidity needs. See "—EME's Liquidity." 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."

Historical Distributions Received By EME

The following table is presented as an aid in understanding the cash flow of EME's continuing operations and its various subsidiary holding companies which depend on distributions from subsidiaries and affiliates to fund general and administrative costs and debt service costs of recourse debt.

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Distributions from Consolidated Operating Projects:			
Edison Mission Midwest Holdings (Illinois Plants)(1)	$ 660	$ 542	$ 330(2)
EME Homer City (Homer City facilities)	187	—	86
Holding company for Storm Lake project	5	11	—
Holding companies of other consolidated operating projects	7	5	1
Distributions from Unconsolidated Operating Projects:			
Edison Mission Energy Funding Corp. (Big 4 projects)(3)	107	116	122
Sunrise Power Company	24	22	20
Holding company for Doga project	23	—	17
Holding companies for Westside projects	12	16	17
Holding companies of other unconsolidated operating projects	5	1	5
Total Distributions	$1,030	$ 713	$ 598

(1) Subsequent to December 31, 2007, Edison Mission Midwest Holdings made an additional distribution of $35 million.

(2) In April 2005, EME made a capital contribution of $300 million which was used to repay debt.

(3) The Big 4 projects consist of investments in the Kern River project, Midway-Sunset project, Sycamore project and Watson project. Distributions reflect the amount received by EME after debt service payments by Edison Mission Energy Funding Corp.

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 net tax-allocation payments to Edison International of $112 million and $151 million in 2007 and 2006, 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 December 31, 2007 or for the twelve months ended December 31, 2007:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Illinois Plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.23 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	4.16 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, enter into swap agreements, 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 December 31, 2007, EME had no borrowings and $93 million of letters of credit outstanding under this credit facility.

Contractual Obligations, Commitments and Contingencies

Contractual Obligations

The following table summarizes EME's significant consolidated contractual obligations as of December 31, 2007.

		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)	$ 6,866	$ 297	$ 592	$ 580	$ 5,397
Operating lease obligations	4,108	363	706	657	2,382
Purchase obligations:					
Capital improvements	253	249	4	—	—
Turbine commitments	1,073	484	589	—	—
Fuel supply contracts	941	440	481	18	2
Gas transportation agreements	84	8	16	16	44
Coal transportation	568	245	323	—	—
Other contractual obligations	93	28	47	16	2
Employee benefit plan contribution(2)	23	23	—	—	—
Total Contractual Obligations(3)	$14,009	$ 2,137	$ 2,758	$ 1,287	$ 7,827

(1) See "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 8. Financial Instruments" for additional details. 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 2008 are not available. For more information, see "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 11. Compensation and Benefit Plans—Pension Plans and Postretirement Benefits Other than Pensions."

(3) At December 31, 2007, EME had a total net liability recorded for uncertain tax positions of $97 million, which is excluded from the table. EME cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the Internal Revenue Service. For more information, see "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 10. Income Taxes."

Operating Lease Obligations

At December 31, 2007, 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 $337 million in 2008, $336 million in 2009, $325 million in 2010, $311 million in 2011, $311 million in 2012, and the minimum lease payments due after 2012 are $2.3 billion. For further discussion, see "—Off-Balance Sheet Transactions—Sale-Leaseback Transactions."

Purchase Obligations

Capital Improvements

At December 31, 2007, EME's subsidiaries had firm commitments for capital and construction expenditures. The majority of these expenditures relate to the construction of wind 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, 2007, EME had entered into agreements with vendors securing 483 wind turbines (1,076 MW) with remaining commitments of $481 million in 2008, $540 million in 2009 and $49 million in 2010. In addition, EME had 30 wind turbines (90 MW) in temporary storage to be used for future wind projects with remaining commitments of $3 million in 2008.

Fuel Supply Contracts

At December 31, 2007, Midwest Generation and EME Homer City had fuel purchase commitments with various third-party suppliers. 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 and Transportation Price Risk."

Gas Transportation Agreements

At December 31, 2007, 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 10 years.

Coal Transportation Agreements

At December 31, 2007, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities. 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 2008 as EME Homer City diversifies its alternative modes of transporting coal to the plant site.

Commercial Commitments

Standby Letters of Credit

As of December 31, 2007, standby letters of credit aggregated to $97 million and were scheduled to expire as follows: $89 million in 2008 and $8 million in 2009.

Guarantees and Indemnities

EME and certain of its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, guarantees of debt and indemnifications.

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 continues 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 had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic removal provision, it has been extended until February 2009. 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 207 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2007. Midwest Generation had recorded a $54 million liability at December 31, 2007 related to this matter.

Midwest Generation engaged an independent actuary in 2004 to complete an estimate of future losses. Based on the actuary's analysis, Midwest Generation recorded an undiscounted liability for its indemnity for future asbestos claims through 2045. During the fourth quarter of 2007, the actuary report was updated and the liability reduced by $9 million. 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 no asbestos claims will be filed after 2044.

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 December 31, 2007, EME had recorded a liability of $101 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. At December 31, 2007, EME had recorded a liability of $12 million related to these matters.

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. The obligations under this indemnification agreement as of December 31, 2007, if payment were required, would be $73 million. EME has not recorded a liability related to this indemnity.

Contingencies

FERC Notice Regarding Investigatory Proceeding against EMMT

In 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 EPAct 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. Discussions to date have been constructive and may lead to a settlement agreement acceptable to both parties. Should these discussions not result in a settlement and a formal proceeding 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 in the bidding practices that it employed, and intends to contest vigorously any allegation of violation.

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 FPA.

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 under separate qualifying facility contracts. As a seller into the California Markets, Midway-Sunset is potentially liable for refunds to entities that purchased in those markets.

In December 2007, Midway-Sunset and other parties to the proceeding entered into a settlement and release of claims agreement with respect to the refund claims, which is currently pending before the FERC. Concurrently with the execution of the settlement and release of claims agreement, Midway-Sunset, SCE and PG&E entered into an agreement pursuant to which PG&E and SCE have agreed to reimburse Midway-Sunset, on a pro-rated basis, for refund liability resulting from sales made into the California Markets on their behalf, and PG&E has also agreed to pay to Midway-Sunset amounts outstanding for qualifying facility power sold by Midway-Sunset to PG&E and deemed delivered on its behalf prior to PG&E's declaration of bankruptcy. Midway-Sunset expects to receive approximately $1 million as a result of these transactions.

Settlement with Illinois Attorney General

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.

Legal actions, including a complaint at the FERC by the Illinois Attorney General and two class action lawsuits, were instituted against successful participants in the 2006 Illinois power procurement auction, including EMMT. 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. Enacting legislation for the settlement was signed on August 28, 2007.

As part of the settlement, Midwest Generation 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, all auction-related complaints filed by the Illinois Attorney General at the FERC, the Illinois Commerce Commission and in the Illinois courts were dismissed and the legislature enacted a rate relief plan.

Midwest Generation made a payment of $7.5 million in September 2007 and is obligated to make 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, Illinois imposes an electric rate freeze or an additional tax on generators. EME records the payments made under this agreement as an expense when paid.

Midwest Generation Potential Environmental Proceeding

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990's and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement 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 CAA, 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 CAA. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. As a result, Midwest Generation is investigating the claims made by the US EPA in the NOV and has identified several defenses which it will raise if the government files suit. At this early stage in the process, Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations or financial position.

On August 13, 2007, Midwest Generation and Commonwealth Edison received a letter signed by several Chicago-based environmental action groups stating that, in light of the NOV, the groups are examining the possibility of filing a citizen suit against Midwest Generation and Commonwealth Edison based presumably on the same or similar theories advanced by the US EPA in the NOV.

By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. Midwest Generation and Commonwealth Edison are cooperating with one another in responding to the NOV.

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.

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 PURPA. See "Item 1. 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, 2007, entities which EME has accounted for under the equity method had indebtedness of $359 million, of which $159 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—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 $54 million, $61 million and $72 million in 2007, 2006 and 2005, 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, 2007	Maturity Date of Lessor Debt
			(in millions)		
Powerton/Joliet	$1,367	PSEG/Citigroup, Inc.	$ 238	$ 175.5 Series A	2009
				679.1 Series B	2016
Homer City.............	1,591	GECC/ Metropolitan Life Insurance Company(1)	798	$ 255.0 Series A	2019
				514.1 Series B	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. The following table summarizes the lease payments and rent expense for the three years ended December 31, 2007.

	Years Ended December 31,		
	2007	2006	2005
	(in millions)		
Cash payments under plant operating leases			
Powerton and Joliet facilities	$ 185	$ 185	$ 141
Homer City facilities	151	152	152
Total cash payments under plant operating leases	$ 336	$ 337	$ 293
Rent expense			
Powerton and Joliet facilities	$ 75	$ 75	$ 75
Homer City facilities	102	102	102
Total rent expense	$ 177	$ 177	$ 177

To the extent that EME's cash rent payments exceed the amount levelized over the term of each lease, EME records prepaid rent. At December 31, 2007 and 2006, prepaid rent on these leases was $716 million and $556 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—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)	
2008	$ 4	$ 112	$ 116
2009	5	112	117
2010	5	112	117
2011	9	111	120
2012	11	111	122
Thereafter	1,323	290	1,613
Total	$1,357	$ 848	$2,205

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. However, possible future developments, such as the promulgation of more stringent environmental laws and regulations, future proceedings that may be initiated by environmental and other regulatory authorities, cases in which new theories of liability are recognized, and settlements agreed to by other companies that establish precedent or expectations for the power industry, could affect the costs and the manner in which EME and its subsidiaries conduct their businesses and could require substantial additional capital or operational expenditures or the ceasing of operations at certain of their facilities. There is no assurance that EME's financial position and results of operations would not be materially adversely affected. EME is unable to predict the precise extent to which additional laws and regulations may affect its future operations and capital expenditure 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 or operational expenditures. If EME fails to comply with applicable environmental laws, it may be subject to injunctive relief or penalties and fines imposed by federal and state regulatory authorities.

Air Quality Regulation

The federal CAA, state clean air acts, and federal and state regulations implementing such statutes have substantial impacts on power generation facilities, particularly coal-fired plants. 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 SIPs will affect the costs and the manner in which EME conducts its business, and is expected to 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 Interstate Rule

The CAIR, issued by the US EPA on March 10, 2005, applies to 28 eastern states and the District of Columbia and is intended to address ozone and fine particulate matter attainment issues by reducing regional NO_X and SO_2 emissions. The CAIR reduces the current CAA Title IV Phase II SO_2 emissions allowance cap for 2010 and 2015 by 50% and 65%, respectively. The CAIR also requires reductions in regional NO_X emissions in 2009 and 2015 by 53% and 61%, respectively, from 2003 levels. The CAIR has been challenged in court by state, environmental and industry groups, 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, NO_X and SO_2 emissions at the Illinois Plants. The agreement has been embodied in rule language, called the CPS, and Midwest Generation's obligations under the agreement were conditioned upon the formal adoption of the CPS as a 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 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 with respect to the timing and amount of emissions reductions that 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 NO_X emissions from units to be determined by Midwest Generation in order to achieve an agreed-on fleetwide level of NO_X emissions per million Btu. Capital expenditures for these controls have been previously estimated (in 2006 dollars) to be approximately $450 million. See further discussion below regarding updating the estimated costs of completing environmental improvements.

During the third phase of the plan, the focus will be on the reduction of SO_2 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 the units 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 the third phase. Additional capital expenditures during the third phase of the plan have been previously estimated (in 2006 dollars) 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.

Midwest Generation is in the process of completing preliminary engineering and permitting work and is in the process of selecting a final engineering, procurement and construction contractor for the environmental improvements at the Powerton Station. It is expected that detailed scoping necessary to update the cost estimates at the Powerton Station, and then using such information to update the cost estimates for the environmental improvements included in Phases II and III above, will be completed in 2008. Until such information is completed, the capital expenditures estimates may vary substantially for the reasons described above.

On May 30, 2006, the Illinois EPA submitted a proposed regulation to the Illinois Pollution Control Board (PCB) to implement the Illinois SIP required for compliance with the CAIR. The Illinois CAIR rule became final upon publication in the Illinois Register, which took place on September 7, 2007. Because the CPS involves mercury emissions, the US EPA has moved the CPS from the Illinois CAIR

SIP to the Illinois CAMR SIP, which was pending final action by the US EPA prior to the February 8, 2008 U.S. Court of Appeals decision vacating the federal CAMR, discussed below. The US EPA approved the Illinois CAIR SIP (without the CPS included) effective as of December 17, 2007.

Pennsylvania—

On December 18, 2007, the Pennsylvania Environmental Quality Board approved the Pennsylvania CAIR. This rule has been submitted to the US EPA for approval as part of the Pennsylvania SIP. The Pennsylvania CAIR is substantively similar to the CAIR. EME Homer City will be subject to the federal CAIR rule during 2009 and expects to be able to comply with the NO_X requirement using its existing SCR system. The Pennsylvania CAIR, including both NO_X and SO_2 limits, is expected to become effective in 2010. EME Homer City expects to comply with Pennsylvania CAIR through the continued operation of its scrubber on Unit 3 to reduce SO_2 emissions and the purchase of SO_2 allowances.

Mercury Regulation

By means of a rule published in May 2005, the US EPA established the CAMR, which created the framework for a national, market-based cap-and-trade program to reduce mercury emissions from existing coal-fired power plants to a national cap of 38 tons by 2010 and to 15 tons by 2018, primarily through reductions in mercury achieved by lowering SO_2 and NO_X emissions under the CAIR. States were allowed, but not required, to join the trading program by adopting the CAMR model trading rules. States retained the right to promulgate alternative regulations equivalent to or more stringent than the CAMR cap-and-trade program, as long as the regulations were approved by the US EPA.

At the time that it published the CAMR, the US EPA also published a second rule, formally rescinding its previous finding that mercury emissions from electrical generating facilities had to be regulated as a hazardous air pollutant pursuant to Section 112 of the CAA, which would have imposed technology-based standards on emission sources. Both the CAMR and US EPA's decision to remove oil and coal-fired plants from the list of sources to be regulated under Section 112 of the CAA were challenged in the U.S. Court of Appeals for the D.C. Circuit by various environmental groups and state attorneys general.

On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated both rules and remanded the matter to the US EPA. As a result, until the US EPA takes further action in response to the remand, coal-fired electric generating facilities continue to be sources subject to regulation under Section 112 of the CAA and will be obligated to comply, on a case-by-case basis, with technology-based standards to control emissions of hazardous air pollutants (not necessarily limited to mercury) in accordance with the requirements of Section 112. As described below, EME's coal-fired electric generating facilities are already subject to significant unit-specific mercury emission reduction requirements under Illinois and Pennsylvania law. EME is assessing the potential impact of this decision on the Illinois and Pennsylvania regulations, including whether these regulations will turn out to be more or less stringent than case-by-case maximum achievable control technology (also known as MACT) standards or MACT standards that may eventually be promulgated by the US EPA.

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.

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. The Pennsylvania CAMR SIP, which embodies PADEP's mercury regulation, was pending approval by the US EPA prior to the February 8, 2008 Court of Appeals decision vacating the federal CAMR.

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 and coal washing on the other two units. In order to meet reductions in emissions by the 2015 deadline, it is likely that additional environmental control equipment will need to be installed. If additional environmental equipment is required in the form of flue gas desulfurization equipment, EME would need to make commitments during 2011 or 2012. EME continues to study available environmental control technologies and estimated costs to reduce SO_2 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.

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 as originally proposed 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.

On July 11, 2007 the US EPA issued a proposed rule to make revisions to the primary and secondary national ambient air quality standards for ozone. With regard to the primary standard for ozone, the US EPA proposes to reduce the level of the 8-hour standard to a level within the range of 0.070 to 0.075 parts per million (ppm). The US EPA solicited comment on alternative levels down to 0.060 ppm and up to and including retaining the current 8-hour standard of 0.08 ppm (effectively 0.084 ppm using current data rounding conventions). The rule may require states to impose further emission reductions beyond those necessary to meet the existing standards. EME anticipates that any such further emission 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 NO_X emission rate of 0.25 lb NO_X/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 "NO_X SIP Call" regulation that provided ozone-season NO_X emission allowances to a 19-state region east of the Mississippi. This program provides for NO_X allowance trading similar to the SO_2 (acid rain) trading program already in effect.

During 2004, the Illinois Plants stayed within their NO_X 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 NO_X allocations. In 2006 and 2007, the Illinois Plants used purchased allowances to stay within their NO_X 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 NO_X, SO_2, 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 in early 2008. The SIP for fine particulates is to be submitted to the US EPA by April 5, 2008.

The CPS requires Midwest Generation to install air pollution controls that will contribute to attainment with the ozone and fine particulate matter per National Ambient Air Quality Standards. Midwest Generation expects, but cannot guarantee, that the reductions required under the agreement and the CPS will be sufficient for compliance with future ozone and particulate matter regulations. See "—Clean Air Interstate Rule—Illinois" for further discussion.

Pennsylvania—

In June 2007, the PADEP requested a redesignation of Clearfield and Indiana counties to attainment with respect to the 8-hour ozone standard. The PADEP also submitted a maintenance plan indicating that the existing (and upcoming) regulations controlling emissions of volatile organic compounds and NO_x will result in continued compliance with the 8-hour ozone standard. Accordingly, EME believes that the Homer City facilities will likely not need to install additional pollution control as a result of the 8-hour ozone standard.

With respect to fine particulates, Pennsylvania has not proposed new regulations to achieve compliance with the National Ambient Air Quality Standard for fine particulates. The SIP with respect to this standard is due to the US EPA by April 5, 2008. Although the final form of the SIP is not yet known, at this time, EME does not anticipate that it will be required to install additional pollution controls at the Homer City facilities to meet the expected SIP requirements for fine particulates.

Regional Haze—

In July 1999, the US EPA published the "Regional Haze Rule" to reduce haze and protect visibility in designated federal areas. The goal of the 1999 rule is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions by 2064. 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. The US EPA issued a final rulemaking on regional haze on June 15, 2005. States were required to revise their SIPs by December 2007 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. 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 Interstate Rule—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 are being evaluated by the state.

New Source Review Requirements

Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address CAA NSR compliance issues at the nation's coal-fired power plants. The NSR regulations impose certain requirements on facilities, such as electric generating stations, if modifications are made to air emissions sources at a facility. The US EPA's strategy has included both the filing of suits against a number of power plant owners, and the issuance of administrative notices of violation to a number of 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 CAA 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 CAA 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 August 3, 2007, Midwest Generation received a NOV from the US EPA alleging that Midwest Generation and Commonwealth Edison violated various provisions of the NSR rules as well as state air regulations. See "—Contractual Obligations, Commitments and Contingencies—Contingencies—Midwest Generation Potential Environmental Proceeding" for further discussion.

Water Quality Regulation

Regulations under the federal Clean Water Act require permits for the discharge of pollutants into United States waters and permits for the discharge of storm water flows from certain facilities. The Clean Water Act also regulates the thermal component (heat) of effluent discharges and the location, design, and construction of cooling water intake structures at generating facilities.

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 January 27, 2007, the Second Circuit rejected the US EPA rule and remanded it to the US EPA. Among the key provisions remanded by the court were the use of cost benefit and restoration to achieve compliance with the rule. On July 9, 2007, the US EPA suspended the requirements for cooling water intake structures, pending further rulemaking. The US EPA is expected to begin another rulemaking process by the end of 2008. 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—

On October 26, 2007, the Illinois EPA filed a proposed rule with the Illinois PCB that would establish more stringent thermal and effluent water quality standards for the Chicago Area Waterway System and Lower Des Plaines River. Midwest Generation's Fisk, Crawford, Joliet and Will County stations all use water from the affected waterways for cooling purposes and the rule, if implemented, is expected to affect the manner in which those stations use water for station cooling.

The proposed rule will be the subject of an administrative proceeding before the Illinois PCB and must be approved by the Illinois PCB and the Illinois Joint Committee on Administrative Rules. Following state adoption and approval, the US EPA also must approve the rule. Hearings began on January 28, 2008, and Midwest Generation is a party in those proceedings. At this time, it is not possible to predict the final form of the rule, how it would impact the operation of the affected stations, or the possible compliance costs or liability.

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 entered by the Pennsylvania state court on July 17, 2007. Under the consent order and agreement, EME Homer City paid a civil penalty of $200,000 and agreed to install modifications to its wastewater system to achieve consistent compliance with discharge limits. EME Homer City has operated the wastewater treatment system for twelve months without a selenium exceedance. At this time, EME expects to remain in compliance and consequently does not expect to install additional treatment systems.

Hazardous Substances and Hazardous Waste Laws

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. 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 $3 million at December 31, 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 investigation and/or remediation 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.

Climate Change

Federal Legislative Initiatives

To date, the United States has pursued a voluntary GHG emissions reduction program to meet its obligations as a signatory to the United Nations Framework Convention on Climate Change. As a result of increased attention to climate change in the U.S., however, numerous bills have been introduced in the current session of the U.S. Congress that would reduce GHG emissions in the U.S. Enactment of climate change legislation within the next several years may occur. However, there is still significant uncertainty about the cost of complying with any future GHG emission requirements. These costs will depend upon many factors, including the required levels of GHG emission reductions, the timing of those reductions, whether emission credits will be allocated with or without cost to existing generators, and whether flexible compliance mechanisms, such as a GHG offset program similar to those sanctioned under the CAA for conventional pollutants, will be part of the policy.

In most of the federal proposals to date, emission allowances would be allocated and distributed without cost in the early years of the emission reduction program, followed by decreasing free allocations and increasing auctions of allowances. While debate continues at the national level over domestic climate policy and the appropriate scope and terms of any federal legislation, many states are developing state-specific measures or participating in regional legislative initiatives to reduce GHG 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.

Regional Legislative Initiatives

On November 15, 2007, Illinois became a party to the Midwestern Accord, in which six of the thirteen states in the Midwestern Governors' Association including Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin and the Province of Manitoba, have agreed to seek to develop regional GHG emission reduction goals within one year, and to develop a multi-sector cap-and-trade program to achieve these goals. The accord called for such a program to be implemented in 30 months. On February 19, 2008, the six participating states announced that they will complete a model rule by the end of 2008 that will create the framework for the cap-and-trade program. Once this model rule has been drafted, each of the participating states could adopt the program through legislative action, executive order or other appropriate means. In February 2007, prior to the development of the Midwestern Accord, Illinois Governor Blagojevich announced a goal to reduce Illinois' GHG emissions to 1990 levels by 2020 and to 60% below 1990 levels by 2050.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap-and-trade GHG 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.

In February 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington launched the Western Climate Initiative to develop regional strategies to address climate change. The Western Climate Initiative is identifying, evaluating and implementing collective and cooperative ways to reduce GHG in the region. In the spring of 2007, the Governor of Utah and the Premiers of British Columbia and Manitoba joined the Initiative. Other states and provinces have joined as observers. The Initiative partners set an overall regional goal in August 2007 for reducing GHG emissions to 15% below 2005 levels by 2020. By August 2008, these partners expect to complete the design of a market-based mechanism to help achieve that reduction goal.

Implementing regulations for such regional initiatives are likely to vary from state to state and may be more stringent and costly than federal legislative proposals currently being debated in Congress. It cannot yet be determined whether or to what extent any federal legislative system would preempt regional or state initiatives, although such preemption would greatly simplify compliance and eliminate regulatory duplication. If state and/or regional initiatives are allowed to stand together with federal legislation, generators could be required to purchase allowances to satisfy their state and federal compliance obligations.

State Specific Legislation

In September 2006, California's Governor Schwarzenegger has enacted two laws regarding GHG 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 GHG emissions. AB 32 requires the California Air Resources Board to develop regulations and market mechanisms targeted to reduce California's GHG emissions to 1990 levels by 2020. The California Air Resources Board's mandatory program will take effect commencing 2012 and will implement incremental reductions so that GHG emissions will be reduced to 1990 levels by 2020.

The second law, known as SB 1368, required the California Public Utilities Commission and the California Energy Commission to adopt GHG 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 August 29, 2007, the California Energy Commission adopted regulations pursuant to SB 1368 establishing and implementing GHG emissions performance standards for baseload generation of local publicly owned electric utilities. Utility purchases of power generated by EME's facilities in California are subject to the emissions performance standards established in SB 1368.

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 GHG 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.

Litigation Developments

The speed with which federal regulations and legislation will be adopted will depend in part on decisions rendered in climate change litigation pending before several federal and state courts and the US EPA's response to those decisions. For example, on April 2, 2007, the United States Supreme Court issued an opinion in *Massachusetts et al. v. Environmental Protection Agency, et. al.*, ruling that the US EPA has the authority to regulate GHG emissions of new motor vehicles under the CAA and that it has a duty to (i) determine whether GHG 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 the 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 CAA related to emissions of motor vehicles, a parallel provision of the CAA applies to stationary sources such as electric generators, and there is litigation pending in the D.C. Circuit Court of Appeals, *Coke Oven Task Force v. Environmental Protection Agency*, in which the holding in *Massachusetts v. Environmental Protection Agency, et al.,* may be applied to stationary sources such as power plants.

On December 19, 2007, the Administrator of the US EPA announced that the US EPA would not grant the waiver that California had been seeking under established CAA procedures to implement stringent GHG emission reduction requirements for motor vehicles. At least 16 other states have adopted or announced plans to adopt California's regulations. On January 2, 2008, California sued the US EPA in the 9th Circuit U.S. Court of Appeals challenging the decision to deny California's request for a waiver. While these developments apply only to automotive sources of GHG emissions, they reflect heightened regulatory scrutiny of, and public concern about, GHG emissions across all sectors of the economy, including power generation.

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 another case brought in April 2006, private citizens filed a complaint in the 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. In August 2007, the court dismissed the case entirely. The plaintiffs have appealed this dismissal in the Fifth Circuit Court of Appeals.

On October 18, 2007, the Kansas Department of Health and Environment rejected a permit to construct two proposed coal-fired electrical generators based on the impact to health and the environment arising from the proposed units' emissions of carbon dioxide. This was the first reported rejection of a proposed coal plant permit based on a clean air statute. This decision has been appealed. In addition, there are a number of pending cases in which environmental groups are arguing that air permits for the construction of major coal-fired generating facilities cannot be issued unless the permits include best available control technology to control carbon dioxide emissions. The US EPA has taken the position that such controls are not required until it finalizes regulations relating to carbon dioxide emissions.

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 that would impose additional costs or charges for the emission of carbon dioxide could have a materially adverse effect on EME. EME will continue to monitor the federal, regional and state developments relating to regulation of GHG emissions to determine their impact on its operations. Requirements to reduce emissions of carbon dioxide and other GHG emissions could significantly increase the cost of generating electricity from fossil fuels, especially coal, as well as the cost of purchased power.

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.

This section discusses these market risk exposures under the following headings:

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 ability of regional pools to pay market participants' settlement prices for energy and related products;
- 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 "earnings at risk" to identify, measure, monitor and control its overall market risk exposure with respect to hedge positions of the Illinois Plants, the Homer City facilities, and the merchant wind projects, and "value at risk" to identify, measure, monitor and control its overall risk exposure in respect of its trading positions. The use of these measures 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, and earnings at risk measures the potential change in value of an asset or position, in each case over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of these measures and relying on a single type of risk measurement tool, EME supplements these approaches 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 may grant liens on its property in support of 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 MISO. These trading hubs have been the most liquid locations for hedging purposes. 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 2007, 2006 and 2005.

	24-Hour Northern Illinois Hub Historical Energy Prices(1)		
	2007	**2006**	**2005**
January	$ 35.75	$ 42.27	$ 38.36
February	56.64	42.66	34.92
March	42.04	42.50	45.75
April	48.91	43.16	38.98
May	44.49	39.96	33.60
June	39.76	34.80	42.45
July	43.40	51.82	50.87
August	57.97	54.76	60.09
September	39.68	31.87	53.30
October	50.14	37.80	49.39
November	43.25	41.90	44.03
December	44.36	33.57	64.99
Yearly Average	$ 45.53	$ 41.42	$ 46.39

(1) Energy prices were calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM.

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 month-end market prices for energy per megawatt-hour for the calendar year 2008 and calendar year 2009 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub during 2007:

	24-Hour Northern Illinois Hub Forward Energy Prices(1)	
	2008	2009
January 31, 2007	$ 44.50	$ 45.15
February 28, 2007	44.99	44.85
March 31, 2007	47.92	46.59
April 30, 2007	49.89	49.73
May 31, 2007	50.69	50.46
June 30, 2007	46.09	47.02
July 31, 2007	46.90	48.50
August 31, 2007	44.57	46.49
September 30, 2007	46.80	48.70
October 31, 2007	50.27	51.63
November 30, 2007	47.70	50.37
December 31, 2007	48.06	51.50

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

The following table summarizes Midwest Generation's hedge position (primarily based on prices at the Northern Illinois Hub) at December 31, 2007:

	2008	2009	2010
Energy Only Contracts(1)			
MWh	10,837,600	7,692,290	3,471,950
Average price/MWh(2)	$ 61.27	$ 62.38	$ 62.62
Load Requirements Services Contracts			
Estimated MWh(3)	5,613,433	1,631,859	—
Average price/MWh(4)	$ 64.01	$ 63.65	$ —
Total estimated MWh	16,451,033	9,324,149	3,471,950

(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 December 31, 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.

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 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 the past three years:

	Historical Energy Prices(1) 24-Hour PJM					
	Homer City Busbar			PJM West Hub		
	2007	2006	2005	2007	2006	2005
January	$ 40.30	$ 48.67	$ 45.82	$ 44.63	$ 54.57	$ 49.53
February	64.27	49.54	39.40	73.93	56.39	42.05
March	55.00	53.26	47.42	61.02	58.30	49.97
April	52.42	48.50	44.27	58.74	49.92	44.55
May	48.12	44.71	43.67	53.89	48.55	43.64
June	45.88	38.78	46.63	60.19	45.78	53.72
July	48.23	53.68	54.63	58.89	63.47	66.34
August	55.44	58.60	66.39	71.00	76.57	82.83
September	48.90	33.26	66.67	60.14	34.40	76.82
October	53.89	37.42	67.93	61.11	39.65	77.56
November	47.27	40.13	59.78	55.25	44.83	62.01
December	52.58	35.29	75.03	59.67	40.53	81.97
Yearly Average	$ 51.03	$ 45.15	$ 54.80	$ 59.87	$ 51.08	$ 60.92

(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 month-end market prices for energy per megawatt-hour for the calendar year 2008 and calendar year 2009 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2007:

	24-Hour PJM West Hub Forward Energy Prices(1)	
	2008	2009
January 31, 2007	$ 58.09	$ 56.40
February 28, 2007	59.33	57.96
March 31, 2007	63.37	61.44
April 30, 2007	65.73	64.37
May 31, 2007	66.57	65.97
June 30, 2007	62.36	64.07
July 31, 2007	62.89	64.89
August 31, 2007	58.96	62.45
September 30, 2007	61.71	64.53
October 31, 2007	65.97	67.92
November 30, 2007	62.14	65.89
December 31, 2007	62.49	67.13

(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.

The following table summarizes EME Homer City's hedge position at December 31, 2007:

	2008	2009	2010
MWh	7,232,000	2,867,200	1,022,400
Average price/MWh(1)	$ 60.85	$ 73.84	$ 77.80

(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 December 31, 2007 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

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 RPM for capacity. The purpose of the RPM is to provide a long-term pricing signal for capacity resources. The RPM provides a mechanism for PJM to satisfy the region's need for generation capacity, the cost of which is allocated to load-serving entities through a locational reliability charge.

The following table summarizes the status of capacity sales for Midwest Generation and EME Homer City at December 31, 2007:

	January 1, 2008 to May 31, 2008		June 1, 2008 to May 31, 2009		June 1, 2009 to May 31, 2010	
	Midwest Generation	EME Homer City	Midwest Generation	EME Homer City	Midwest Generation	EME Homer City
Fixed Price Capacity Sales						
Through RPM Auction, Net						
MW	2,603	786	3,283	820	4,614	1,670
Price per MW-day	$ 40.80	$ 40.80	$ 111.92	$ 111.92	$ 102.04	$ 191.32
Non-unit Specific Capacity Sales						
MW	500	—	880	—	715	—
Price per MW-day	$ 21.31	—	$ 64.35	—	$ 71.46	—
Variable Capacity Sales						
MW	—	891	—	891	—	—
Price per MW-day	—	$ 66.71(1)	—	$ 69.50(2)	—	—

(1) Actual contract price is a function of NYISO capacity auction clearing prices in January through April 2008 and forward over-the-counter NYISO capacity prices on December 31, 2007 for May 2008.

(2) Expected price per MW-day is based on forward over-the-counter NYISO prices on December 31, 2007.

In January 2008, the RPM auction took place for the time period from June 1, 2010 through May 31, 2011 which resulted in a fixed price for Midwest Generation and EME Homer City's capacity sold into the auction of $174.29/MW-day. EMMT sold net 4,929 MW of capacity from the Illinois Plants and net 1,813 MW of capacity from the Homer City facilities.

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 the cost of new entry.

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 its available capacity (defined as 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 on a net basis in the table above.

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 is not receiving the RPM auction clearing price for this previously sold capacity. The price EME Homer City is receiving for these capacity sales is a function of NYISO capacity clearing prices resulting from separate NYISO capacity auctions.

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. Effective June 1, 2007, PJM implemented marginal losses which adjust the algorithm that calculates locational marginal prices to include a component for marginal transmission losses in addition to the component included for congestion. 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 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 15%, compared to 12% during 2006 and 10% during 2005. The monthly average difference during 2007 ranged from 10% 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, although the implementation of marginal losses on June 1, 2007 has lowered energy prices at the Illinois Plants busbars.

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 and Transportation 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 December 31, 2007 for the next three years.

	Amount of Coal Under Contract in Millions of Tons(1)		
	2008	**2009**	**2010**
Illinois Plants	17.5	11.7	11.7
Homer City facilities	5.7	4.4	0.3

(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 NAPP coal, which are related to the price of coal purchased for the Homer City facilities, increased steadily during 2007 and decreased slightly in 2006 from 2005. The price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per MMBtu sulfur content) ranged from $44.00 per ton to $55.25 per ton during 2007 and increased to a price of $70.00 per ton at February 15, 2008, as reported by the EIA. The 2007 increase in the NAPP coal price was in line with normal market price volatility. In 2006, the price of NAPP coal fluctuated between $37.50 per ton and $45.00 per ton, with a price of $43.00 per ton at December 15, 2006, as reported by the EIA. 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 EIA. 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.

The price of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per MMBtu sulfur content) purchased for the Illinois Plants increased during 2007 from 2006 year-end prices. The 2007 fluctuations in PRB coal prices were in line with normal market price volatility. Prices of PRB coal decreased during 2006 from 2005 due to easing natural gas prices, fuel switching, lower prices for SO_2 allowances and improved inventory. The price of PRB coal fluctuated between $8.35 per ton to $11.50 per ton during 2007 and increased to a price of $13.10 per ton at February 15, 2008, as reported by the EIA. In 2006, prices ranged from $20.66 per ton in January 2006 to $9.90 per ton at December 15, 2006. In 2005, the price of PRB coal ranged from $6.20 per ton to $18.48 per ton, as reported by the EIA.

EME 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. EME is exposed to price risk related to higher transportation rates after the expiration of its existing transportation contracts. Current transportation rates for PRB coal are higher than the existing rates under contract (transportation costs are more than 50% of the delivered cost of PRB coal to the Illinois Plants).

Based on EME's anticipated coal requirements in 2008 in excess of the amount under contract, EME expects that a 10% change in the price of coal at December 31, 2007 would increase or decrease pre-tax income in 2008 by approximately $2 million.

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO_2 allowances, and Illinois and Pennsylvania regulations implemented the federal NO_X 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 average price of purchased SO_2 allowances was $512 per ton during 2007, $664 per ton during 2006 and $1,219 per ton during 2005. The decrease in the price of SO_2 allowances during 2007 from 2006 year-end prices has been attributed to less demand in the market for SO_2 allowances. The 2006 decrease in the price of SO_2 allowances has been attributed to a decline in natural gas prices and fuel switching from oil to gas. The price of SO_2 allowances, determined by obtaining broker quotes and information from other public sources, was $535 per ton as of December 31, 2007. EME does not anticipate any requirements to purchase SO_2 emission allowances in 2008. 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 Discussion and Analysis of Financial Condition and Results of Operations— 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, 2007:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Non-qualifying hedges			
Illinois Plants	$ (14)	$ 28	$ (17)
Homer City	(1)	2	(1)
Ineffective portion of cash flow hedges			
Illinois Plants	(11)	2	(2)
Homer City	(9)	33	(40)
Total unrealized gains (losses)	$ (35)	$ 65	$ (60)

At December 31, 2007, unrealized losses of $38 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to subsequent periods ($25 million for 2008, $10 million for 2009, and $3 million for 2010).

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):

	December 31, 2007	December 31, 2006
Commodity price:		
Electricity	$ (137)	$ 184

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 change in fair value of electricity contracts at December 31, 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 December 31, 2007, which is the valuation date, causing the fair value of the contracts to become liabilities instead of assets. A 10% change in the market price at December 31, 2007 would increase or decrease the fair value of outstanding derivative commodity price contracts by approximately $210 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 as of December 31, 2007 (in millions):

	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$(137)	$ (41)	$ (96)	$ —	$ —

Energy Trading Derivative Financial Instruments

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

	December 31, 2007		December 31, 2006	
	Assets	Liabilities	Assets	Liabilities
Electricity	$141	$ 9	$313	$207
Other	—	—	5	—
Total	$141	$ 9	$318	$207

The change in the fair value of trading contracts for the year ended December 31, 2007 was as follows (in millions):

Fair value of trading contracts at January 1, 2007	$ 111
Net gains from energy trading activities	149
Amount realized from energy trading activities	(133)
Other changes in fair value	5
Fair value of trading contracts at December 31, 2007	$ 132

A 10% change in the market price at December 31, 2007 would increase or decrease the fair value of trading contracts by approximately $44 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 (as of December 31, 2007) (in millions):

	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 51	$ 44	$ 7	$ —	$ —
Prices based on models and other valuation methods	81	4	16	22	39
Total	$ 132	$ 48	$ 23	$ 22	$ 39

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 December 31, 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	December 31, 2007
	(in millions)
A or higher	$ 40
A-	61
BBB+	81
BBB	16
BBB-	4
Below investment grade	1
Total	$ 203

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 51% of EME's consolidated operating revenues for the year ended December 31, 2007. Moody's rates PJM's senior unsecured debt Aa3. PJM, an ISO 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 December 31, 2007, EME's account receivable due from PJM was $82 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 for the year ended December 31, 2007. Commonwealth Edison's senior unsecured debt rating was downgraded below investment grade by S&P in June 2007 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 December 31, 2007, EME's account receivable due from Commonwealth Edison was $20 million.

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. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of EME's consolidated long-term obligations (including current portion) was $3.8 billion at December 31, 2007, compared to the carrying value of $3.8 billion. A 10% increase in market interest rates at December 31, 2007 would result in a decrease in the fair value of total long-term obligations by approximately $187 million. A 10% decrease in market interest rates at December 31, 2007 would result in an increase in the fair value of total long-term obligations by approximately $202 million.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is filed with this report under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

EME's management, with the participation of the company's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of EME's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period, EME's disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting

EME's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, EME's management conducted an evaluation of the effectiveness of EME's internal control over financial reporting based on the framework set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on its evaluation under the COSO framework, EME's management concluded that EME's internal control over financial reporting was effective as of December 31, 2007.

Internal Control Over Financial Reporting

There were changes as described below in EME's internal control over financial reporting (as that term is defined in Rules 13a-15(f) or 15d-15(f) under the Exchange Act) during the period to which this report relates that have materially affected, or are reasonably likely to materially affect, EME's internal control over financial reporting.

During 2007, EME implemented a series of SAP ERP modules, including the general ledger, chart of accounts, consolidation, reporting, and accounts payable. In addition, procurement and materials management and fuel management systems were implemented at the Illinois Plants and the Homer City facilities. The introduction of these ERP modules and the related workflow capabilities resulted in changes to EME's financial reporting controls and procedures, with such changes identified during the implementation of the ERP modules. EME has modified the design and documentation of internal control processes and procedures relating to the new system to supplement and complement existing internal controls over financial reporting. The system changes were undertaken to integrate systems and consolidate information, and were not undertaken in response to any actual or perceived deficiencies in EME's internal control over financial reporting.

ITEM 9A(T). CONTROLS AND PROCEDURES

This annual report does not include an attestation report of EME's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by EME's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit EME to provide only management's report in this annual report.

ITEM 9B. OTHER INFORMATION

None.

EDISON MISSION ENERGY AND SUBSIDIARIES
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Edison Mission Energy:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Edison Mission Energy and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007. As discussed in Notes 1 and 11 to the consolidated financial statements, the Company changed the manner in which it accounts for stock-based compensation and defined benefit pension plans and other postretirement plans as of January 1, 2006 and December 31, 2006, respectively. As discussed in Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of December 31, 2005.

/s/ PricewaterhouseCoopers LLP
Los Angeles, California
February 27, 2008

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Years Ended December 31,		
	2007	2006	2005
Operating Revenues	$ 2,580	$ 2,239	$ 2,265
Operating Expenses			
Fuel	684	645	617
Plant operations	584	511	493
Plant operating leases	176	176	177
Depreciation and amortization	162	144	134
Loss on sale of assets and asset impairment charges	1	—	7
Administrative and general	209	140	154
Total operating expenses	1,816	1,616	1,582
Operating income	764	623	683
Other Income (Expense)			
Equity in income from unconsolidated affiliates	200	186	229
Impairment loss on equity method investment	—	—	(55)
Dividend income	12	2	—
Interest income	85	97	62
Interest expense	(273)	(279)	(300)
Loss on early extinguishment of debt	(160)	(146)	(4)
Other income (expense), net	6	21	7
Total other income (expense)	(130)	(119)	(61)
Income from continuing operations before income taxes and minority interest	634	504	622
Provision for income taxes	219	189	208
Minority interest	1	1	—
Income From Continuing Operations	416	316	414
Income (loss) from operations of discontinued subsidiaries, net of tax (Note 5)	(2)	98	29
Income Before Accounting Change	414	414	443
Cumulative effect of change in accounting, net of tax (Notes 1 and 7)	—	—	(1)
Net Income	$ 414	$ 414	$ 442

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

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2007	December 31, 2006
Assets		
Current Assets		
Cash and cash equivalents	$ 994	$ 1,213
Short-term investments	81	558
Accounts receivable—trade	224	178
Receivables from affiliates	35	51
Inventory	149	158
Derivative assets	56	272
Margin and collateral deposits	103	69
Deferred taxes	21	—
Prepaid expenses and other	89	96
Total current assets	1,752	2,595
Investments in Unconsolidated Affiliates	387	367
Property, Plant and Equipment	4,942	4,272
Less accumulated depreciation and amortization	1,053	981
Net property, plant and equipment	3,889	3,291
Other Assets		
Deferred financing costs	41	45
Long-term derivative assets	91	114
Restricted cash	48	91
Rent payments in excess of levelized rent expense under plant operating leases	716	556
Long-term margin and collateral deposits	18	4
Other long-term assets	366	187
Total other assets	1,280	997
Total Assets	$ 7,308	$ 7,250

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

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2007	December 31, 2006
Liabilities and Shareholder's Equity		
Current Liabilities		
Accounts payable	$ 73	$ 69
Payables to affiliates	17	6
Accrued liabilities	289	270
Derivative liabilities	49	82
Interest payable	30	28
Deferred taxes	—	59
Current maturities of long-term obligations	17	132
Total current liabilities	475	646
Long-term obligations net of current maturities	3,806	3,035
Deferred taxes and tax credits	351	347
Deferred revenues	65	61
Long-term derivative liabilities	103	9
Other long-term liabilities	543	523
Total Liabilities	5,343	4,621
Minority Interest	42	47
Commitments and Contingencies (Notes 8, 9 and 12)		
Shareholder's Equity		
Common stock, par value $0.01 per share; 10,000 shares authorized; 100 shares issued and outstanding as of December 31, 2007 and 2006	64	64
Additional paid-in capital	1,326	2,174
Retained earnings	596	243
Accumulated other comprehensive income (loss)	(63)	101
Total Shareholder's Equity	1,923	2,582
Total Liabilities and Shareholder's Equity	$ 7,308	$ 7,250

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

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY
(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Shareholder's Equity
Balance at December 31, 2004	$ 64	$ 2,277	$ (613)	$ 17	$ 1,745
Net income			442		442
Other comprehensive loss				(228)	(228)
Non-cash equity contribution		20			20
Cash dividends to parent		(62)			(62)
Payments to Edison International for stock option price appreciation on options exercised, net of tax		(4)			(4)
Other stock transactions, net		(3)			(3)
Balance at December 31, 2005	64	2,228	(171)	(211)	1,910
Net income			414		414
Other comprehensive income				318	318
Adjustment to initially apply SFAS No. 158, net of tax				(6)	(6)
Non-cash equity contribution		8			8
Cash dividends to parent		(50)			(50)
Payments to Edison International for stock option price appreciation on options exercised, net of tax		(10)			(10)
Other stock transactions, net		(2)			(2)
Balance at December 31, 2006	64	2,174	243	101	2,582
Net income			414		414
Impact upon adoption of FIN No. 48			(1)		(1)
Other comprehensive loss				(164)	(164)
Cash contribution from parent		36			36
Cash dividends to parent		(899)	(26)		(925)
Payments to Edison International for stock purchases related to stock-based compensation			(34)		(34)
Excess tax benefits related to stock-option exercises		11			11
Other stock transactions, net		4			4
Balance at December 31, 2007	$ 64	$ 1,326	$ 596	$ (63)	$ 1,923

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

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2007	**2006**	**2005**
Net Income	$ 414	$ 414	$ 442
Other comprehensive income (loss), net of tax:			
Pension and postretirement benefits other than pensions:			
Prior service adjustment, net of tax	(1)	—	—
Amortization of prior service, net of tax	(1)	—	—
Net gain adjustment, net of tax	7	—	—
Amortization of net loss, net of tax benefit	2	—	—
Minimum pension liability adjustment, net of income tax effect	—	(3)	—
Unrealized gains (losses) on derivatives qualified as cash flow hedges:			
Other unrealized holding gains (losses) arising during period, net of income tax expense (benefit) of $(160), $211 and $(54) for 2007, 2006 and 2005, respectively	(235)	309	(69)
Reclassification adjustments included in net income, net of income tax expense (benefit) of $(45), $(9) and $107 for 2007, 2006 and 2005, respectively	64	12	(159)
Other comprehensive income (loss)	(164)	318	(228)
Comprehensive Income	$ 250	$ 732	$ 214

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

EDISON MISSION ENERGY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2007	**2006**	**2005**
Cash Flows From Operating Activities			
Net income	$ 414	$ 414	$ 442
Less: Income from discontinued operations	2	(98)	(29)
Income from continuing operations, net	416	316	413
Adjustments to reconcile income to net cash provided by (used in) operating activities:			
Equity in income from unconsolidated affiliates	(199)	(183)	(227)
Distributions from unconsolidated affiliates	137	170	222
Depreciation and amortization	172	158	142
Minority interest	(1)	—	—
Deferred taxes and tax credits	41	100	(76)
Loss on sale of assets	1	—	—
Loss on early extinguishment of debt	160	146	4
Impairment charges	—	—	62
Cumulative effect of change in accounting, net of tax	—	—	1
Changes in operating assets and liabilities:			
Decrease (increase) in margin and collateral deposits	(48)	625	(656)
Decrease (increase) in receivables	(29)	125	(118)
Decrease (increase) in inventory	9	(38)	(13)
Decrease (increase) in prepaid expenses and other	6	(26)	13
Increase in rent payments in excess of levelized rent expense	(160)	(161)	(117)
Increase (decrease) in accounts payable and other current liabilities	(9)	—	9
Increase (decrease) in interest payable	2	(23)	(4)
Decrease (increase) in derivative assets and liabilities	26	(72)	41
Other operating—assets	(18)	(1)	4
Other operating—liabilities	13	(5)	61
Operating cash flow from continuing operations	519	1,131	(239)
Operating cash flow from discontinued operations	(2)	94	20
Net cash provided by (used in) operating activities	517	1,225	(219)
Cash Flows From Financing Activities			
Borrowings on long-term debt	2,930	1,450	330
Payments on long-term debt agreements	(2,276)	(1,683)	(712)
Cash contribution from parent	36	—	—
Cash dividends to parent	(925)	(51)	(367)
Payments to affiliates related to stock-based awards	(34)	(27)	(18)
Excess tax benefits related to stock-based awards	14	7	—
Premium paid on extinguishment of debt and financing costs	(162)	(157)	(6)
Net cash used in financing activities	(417)	(461)	(773)
Cash Flows From Investing Activities			
Capital expenditures	(540)	(310)	(61)
Proceeds from return of capital and loan repayments	32	41	—
Purchase of interest of acquired companies	(33)	(18)	(154)
Proceeds from sale of interest in projects	—	43	—
Proceeds from sale of discontinued operations	—	—	124
Purchase of short-term investments	(20)	(512)	(183)
Maturities and sales of short-term investments	497	137	140
Decrease in restricted cash	43	14	41
Investments in other assets	(298)	(101)	(41)
Investing cash flow from continuing operations	(319)	(706)	(134)
Investing cash flow from discontinued operations	—	—	5
Net cash used in investing activities	(319)	(706)	(129)
Effect of consolidation of variable interest entities on cash	—	—	3
Net increase (decrease) in cash and cash equivalents	(219)	58	(1,118)
Cash and cash equivalents at beginning of period	1,213	1,155	2,274
Cash and cash equivalents at end of period	994	1,213	1,156
Cash and cash equivalents classified as part of discontinued operations	—	—	(1)
Cash and cash equivalents of continuing operations	$ 994	$ 1,213	$ 1,155

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

Note 1. Summary of Significant Accounting Policies

EME is a wholly owned subsidiary of MEHC, which is a wholly owned subsidiary of Edison Mission Group Inc., which is a wholly owned, non-utility subsidiary of Edison International, which is also the parent holding company of SCE. Through its subsidiaries, 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.

Each of EME's direct and indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Any asset of any of those subsidiaries may not be available to satisfy EME's obligations or any obligations of EME's other subsidiaries. However, unrestricted cash or other assets which are available for distribution may, subject to business and tax considerations, applicable law and the terms of financing arrangements binding on these subsidiaries, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or its affiliates.

Basis of Presentation

The consolidated financial statements include the accounts of EME and all subsidiaries and partnerships in which EME has a controlling interest and variable interest entities in which EME is deemed the primary beneficiary. EME's investments in unconsolidated affiliates in which a significant, but less than controlling, interest is held and variable interest entities, in which EME is not deemed to be the primary beneficiary, are accounted for by the equity method. Refer to Note 4—Acquisitions and Consolidations—Consolidations, for a discussion of EME's adoption of an accounting standard on variable interest entities. All significant intercompany transactions and balances have been eliminated in the consolidated financial statements.

Certain prior year reclassifications have been made to conform to the current year financial statement presentation. Except as indicated, amounts reflected in the notes to the consolidated financial statements relate to continuing operations of EME.

The preparation of financial statements in conformity with GAAP requires EME to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from those estimates.

Cash Equivalents and Short-term Investments

Cash equivalents consist of time deposits, including certificates of deposit ($141 million and $289 million at December 31, 2007 and 2006, respectively), and other investments ($732 million and $824 million at December 31, 2007 and 2006, respectively) with original maturities of three months or less. For a discussion of restricted cash, see "—Restricted Cash."

At December 31, 2007 and 2006, EME had classified all marketable debt securities as held-to-maturity under SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The securities were carried at amortized cost plus accrued interest which approximated their fair value. Gross unrealized holding gains and losses were not material.

Held-to-maturity securities, which all mature within one year, consisted of the following:

	December 31, 2007	December 31, 2006
	(in millions)	
Commercial paper	$ 32	$ 417
Certificates of deposit	41	141
Treasury bills	7	—
Corporate bonds	1	—
Total	$ 81	$ 558

In addition, EME had marketable securities classified as available-for-sale under SFAS No. 115 during 2005. Sales of auction rate securities were $140 million in 2005. Unrealized gains and losses from investments in these securities were not material.

Deferred Financing Costs

Bank, legal and other direct costs incurred in connection with obtaining financing are deferred and amortized as interest expense on a basis which approximates the effective interest rate method over the term of the related debt. Accumulated amortization of these costs at December 31, 2007 and 2006 amounted to $14 million and $24 million, respectively. Amortization of deferred financing costs charged to operations was $3 million and $5 million in 2007 and 2006, respectively.

Derivative Instruments

SFAS No. 133, as amended and interpreted by other related accounting literature, establishes accounting and reporting standards for derivative instruments (including certain derivative instruments embedded in other contracts). SFAS No. 133 requires companies to record derivatives on their balance sheets as either assets or liabilities measured at their fair value unless exempted from derivative treatment as a normal sale and purchase. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met, which requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

SFAS No. 133 sets forth the accounting requirements for cash flow hedges. SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings.

Financial instruments that are utilized for trading purposes are measured at fair value and included in the balance sheet as derivative assets or liabilities. In the absence of quoted market prices, financial instruments are valued at fair value, considering time value, 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 in accordance with EITF No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Derivative assets include the fair value of open financial positions related to trading activities and the present value of net amounts receivable from structured transactions. Derivative liabilities include the fair value of open financial positions related to trading activities. The results of derivative activities are recorded as part of cash flows from operating activities in the accompanying consolidated statements of cash flows.

Where EME's derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation (FIN) 39 "Offsetting of Amounts Related to Certain Contracts" are met, EME presents its derivative assets and liabilities on a net basis in its balance sheet.

Impairment of Investments and Long-Lived Assets

EME evaluates the impairment of its investments in projects and other long-lived assets based on a review of estimated future cash flows expected to be generated whenever events or changes in circumstances indicate that the carrying amount of such investments or assets may not be recoverable. If the carrying amount for an equity method investment exceeds fair value, an impairment loss is recorded if the decline is other than temporary in accordance with Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." If the carrying amount of a long-lived asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, then an impairment loss is recognized in accordance with SFAS No. 144.

Income Taxes

EME is included in the consolidated federal and state income tax returns of Edison International and participates in tax-allocation and payment agreements with other subsidiaries of Edison International. EME calculates its tax provision in accordance with these tax agreements. EME's current tax liability or benefit is determined on a "with and without" basis. This means Edison International computes its combined federal and state tax liabilities including and excluding EME's taxable income or loss and state apportionment factors. This method is similar to a separate company return, except that EME recognizes, without regard to separate company limitations, additional tax liabilities or benefits based on the impact to the combined group of including EME's taxable income or losses and state apportionment factors.

EME accounts for deferred income taxes using the asset-and-liability method, wherein deferred tax assets and liabilities are recognized for future tax consequences of temporary differences between the carrying amounts and the tax bases of assets and liabilities using enacted income tax rates. Investment and energy tax credits are deferred and amortized over the term of the power purchase agreement of the respective project while production tax credits are recognized when earned. EME's investments in wind-powered electric generation projects qualify for federal production tax credits under Section 45 of the Internal Revenue Code. Such credits are allowable for production during the 10-year period after a qualifying wind energy facility is placed into service. Certain of EME's wind projects also qualify for state tax credits which are accounted for similarly as federal production tax credits.

Interest expense and penalties associated with income taxes are reflected in the caption "Provision for income taxes" on the consolidated statements of income. Income tax accounting policies are discussed further in Note 10—Income Taxes.

Intangible Assets

EME accounts for acquired intangible assets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." Under SFAS No. 142, acquired intangible assets with indefinite lives are not amortized, rather they are tested for impairment. Intangible assets are periodically reviewed when impairment indicators are present to assess recoverability from future operations using undiscounted future cash flows in accordance with SFAS No. 144. For project development rights, the assets are subject to ongoing impairment analysis, such that if a project is no longer expected, the capitalized costs are written off.

Current intangible assets reflected in the caption "Prepaid expenses and other" on EME's consolidated balance sheet, consist of emission allowances purchased by EME and amounted to $45 million at December 31, 2007.

Noncurrent intangible assets reflected in the caption "Other long-term assets" on EME's consolidated balance sheets consist of the following:

	December 31,	
	2007	2006
	(in millions)	
Amortized intangible assets:		
Gross carrying amount	$ 5	$ 5
Less accumulated amortization	1	—
Amortized intangible assets—net	$ 4	$ 5
Unamortized intangible assets:		
Project development rights	$ 14	$ 13
Option rights	24	—
Emission allowances(1)	23	—
Unamortized intangible assets	$ 61	$ 13

(1) Emission allowances do not have a pre-determined contractual term or expiration date. Emission allowances are stated at weighted average cost.

Amortized intangible assets are amortized using the straight-line method over five years. Total amortization expense for intangible assets subject to amortization was approximately $1 million for the year ended December 31, 2007. Amortization expense is expected to approximate $1 million each year in the next four years.

In 2007 and 2006, project development rights relate to the consolidation of a development stage enterprise. See Note 4—Acquisitions and Consolidations—Consolidations—Consolidations of Special Purpose Entities, for further discussion. In 2007, EME acquired six projects in Texas and Oklahoma which are in various stages of development with target completion dates of 2008 and beyond. The initial purchase price paid was recorded as project development rights. In 2007, EME recorded option rights pursuant to EME's joint development agreement entered into in December 2007 to develop jointly a portfolio of projects located in Arizona, Nevada and New Mexico. EME paid $24 million to acquire a 1% interest in twelve designated projects and the option to purchase the remaining 99%. The projects are in development with target completion dates generally beyond 2008. EME is required to fund ongoing development expenses for each project.

Inventory

Inventory is stated at the lower of weighted average cost or market. Inventory at December 31, 2007 and December 31, 2006 consisted of the following:

	December 31, 2007	December 31, 2006
	(in millions)	
Coal and fuel oil	$ 100	$ 112
Spare parts, materials and supplies	49	46
Total	$ 149	$ 158

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in fair value of the related positions. See "New Accounting Pronouncements—Accounting Principle's Not Yet Adopted—FASB Staff Position FIN No. 39-1" for a discussion of EME's adoption of an accounting pronouncement that will result in netting a portion of margin and cash collateral deposits with derivative liabilities on EME's consolidated balance sheets.

New Accounting Pronouncements

Accounting Principles Adopted

Statement of Financial Accounting Standards Interpretation No. 48—

In July 2006, the FASB issued 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 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 year ended December 31, 2007.

Accounting Principles Not Yet Adopted

FASB Staff Position FIN No. 39-1—

In April 2007, the FASB issued FIN No. 39-1. 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 in the first quarter of 2008. The adoption is expected to 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.

Statement of Financial Accounting Standards No. 159—

In February 2007, the FASB issued 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. EME will adopt this pronouncement in the first quarter of 2008. Since EME elected not to report any current financial assets and liabilities at fair value, the adoption will not result in any cumulative-effect adjustment to retained earnings.

Statement of Financial Accounting Standards No. 157—

In September 2006, the FASB issued 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 in the first quarter of 2008. The adoption is not expected to result in any retrospective adjustment to its consolidated financial statements. The accounting requirements for employers' pension and other postretirement benefit plans is effective at the end of 2008, which is the next measurement date for these benefit plans. The effective date will be January 1, 2009 for asset retirement obligations and other nonfinancial liabilities which are not measured or disclosed on a recurring basis (at least annually).

Statement of Financial Accounting Standards No. 141(R)—

In December 2007, the FASB issued SFAS No. 141(R), which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS No. 141(R) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after fiscal years beginning January 1, 2009. Early adoption is not permitted.

Statement of Financial Accounting Standards No. 160—

In December 2007, the FASB issued SFAS No. 160, which requires an entity to clearly identify and present ownership interests in subsidiaries held by parties other than the entity in the consolidated financial statements within the equity section but separate from the entity's equity. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interest be accounted for similarly as equity transactions; and when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary be measured at fair value. EME will adopt SFAS No. 160 on January 1, 2009. In accordance with this standard, EME will reclassify minority interest to a component of shareholder's equity (at December 31, 2007 this amount was $42 million).

Planned Major Maintenance

Certain of EME's plant facilities' major pieces of equipment require major maintenance on a periodic basis. These costs are expensed as incurred.

Project Development Costs

EME capitalizes direct costs incurred in developing new projects upon attainment of principal activities needed to commence procurement and construction. These costs consist of professional fees, salaries, permits, and other directly related development costs incurred by EME. The capitalized costs are amortized over the life of operational projects or charged to expense if management determines the costs to be unrecoverable.

Property, Plant and Equipment

Property, plant and equipment, including leasehold improvements and construction in progress, are capitalized at cost and are principally comprised of EME's majority-owned subsidiaries' plants and related facilities. Depreciation and amortization are computed by using the straight-line method over the useful life of the property, plant and equipment and over the lease term for leasehold improvements.

As part of the acquisition of the Illinois Plants and the Homer City facilities, EME acquired emission allowances under the US EPA's Acid Rain Program. Although the emission allowances granted under this program are freely transferable, EME intends to use substantially all the emission allowances in the normal course of its business to generate electricity. Accordingly, EME has classified emission allowances expected to be used by EME to generate power as part of property, plant and equipment. Acquired emission allowances will be amortized on a straight-line basis.

Useful lives for property, plant and equipment are as follows:

Power plant facilities	3 to 30 years
Leasehold improvements	Shorter of life of lease or estimated useful life
Emission allowances	25 to 33.75 years
Equipment, furniture and fixtures	3 to 7 years
Capitalized leased equipment	5 years

Interest incurred on funds borrowed by EME to finance project construction is capitalized. Capitalization of interest is discontinued when the projects are completed and deemed operational. Such capitalized interest is included in investment in energy projects and property, plant and equipment.

Capitalized interest is amortized over the depreciation period of the major plant and facilities for the respective project.

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Interest incurred	$ 297	$ 287	$ 300
Interest capitalized	(24)	(8)	—
	$ 273	$ 279	$ 300

Rent Expense

Minimum lease payments under operating leases are levelized (total minimum lease payments divided by the number of years of the lease) and recorded as rent expense over the terms of the leases. Lease payments in excess of the minimum are recorded as rent expense in the year incurred. Operating leases primarily consist of long-term leases for the Powerton, Joliet and Homer City power plants. See Note 12—Commitments and Contingencies—Lease Commitments, for additional information on these sale-leaseback transactions.

Restricted Cash

Certain cash balances are restricted primarily to pay amounts required for lease payments and letter of credit expenses. The total restricted cash included in EME's consolidated balance sheet was $48 million at December 31, 2007 and $91 million at December 31, 2006. Included in restricted cash were $30 million and $40 million at December 31, 2007 and 2006, respectively, related to lease payments and collateral reserves of $18 million and $38 million at December 31, 2007 and 2006, respectively.

Revenue Recognition

EME is primarily an independent power producer, operating a portfolio of owned and leased plants and plants which are accounted for under the equity method. EME's subsidiaries enter into power and fuel hedging, optimization transactions and energy trading contracts, all subject to market conditions. One of EME's subsidiaries executes these transactions primarily through the use of physical forward commodity purchases and sales and financial commodity swaps and options. With respect to its physical forward contracts, EME's subsidiaries generally act as the principal, take title to the commodities, and assume the risks and rewards of ownership. Therefore, EME's subsidiaries record settlement of non-trading physical forward contracts on a gross basis. Consistent with Emerging Issues Task Force No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes," EME nets the cost of purchased power against related third party sales in markets that use locational marginal pricing, currently PJM. Financial swap and option transactions are settled net and, accordingly, EME's subsidiaries do not take title to the underlying commodity. Therefore, gains and losses from settlement of financial swaps and options are recorded net in operating revenues in the accompanying consolidated income statements. Managed risks typically include commodity price risk associated with fuel purchases and power sales.

EME records revenue and related costs as electricity is generated or services are provided unless EME is subject to SFAS No. 133 and does not qualify for the normal sales and purchases exception.

In addition, revenues under certain long-term power sales contracts subject to Emerging Issues Task Force No. 91-6, "Revenue Recognition of Long-term Power Sales Contracts," are recognized based on the output delivered at the lower of the amount billable or the average rate over the contract term. The excess of the amounts billed over the portion recorded as revenue is reflected in deferred revenues in the consolidated balance sheet.

Stock-Based Compensation

Edison International's stock options, performance shares, deferred stock units and, beginning in 2007, restricted stock units have been granted to EME employees under Edison International's long-term incentive compensation programs. Edison International usually does not issue new common stock for equity awards settled. Rather, a third party is used to facilitate the exercise of stock options and the purchase and delivery of outstanding common stock for settlement of option exercises, performance shares, and restricted stock units. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Deferred stock units granted to management are settled in cash, not stock and represent a liability. Restricted stock units are settled in common stock; however, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

On April 26, 2007, Edison International's shareholders approved a new incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. No additional awards were granted under Edison International's prior stock-based compensation plans on or after April 26, 2007, and all future issuances will be made under the new plan. The maximum number of shares of Edison International's common stock that may be issued or transferred pursuant to awards under the new incentive plan is 8.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued. As of December 31, 2007, Edison International had approximately 8.4 million shares remaining for future issuance under its stock-based compensation plan. For further discussion, see Note 11—Compensation and Benefit Plans—Stock-Based Compensation.

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 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 $14 million and $7 million of excess tax benefits are classified as financing cash inflows in 2007 and 2006, respectively.

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.

Prior to January 1, 2006, EME accounted for these plans using the intrinsic value method. Upon grant, no stock-based compensation cost for stock options was reflected in net income, as the grant date was the measurement date, and all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Previously, stock-based compensation cost for performance shares was remeasured at each reporting period and related compensation expense was adjusted. As discussed in "New Accounting Pronouncements" above, effective January 1, 2006, EME implemented SFAS No. 123(R) that requires companies to use the fair value accounting method for stock-based compensation resulting in the recognition of expense for all stock-based compensation awards. EME recognizes stock-based compensation expense on a straight-line basis over the requisite service period. EME recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, EME recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006 to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation is recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement. If EME recognized stock-based compensation expense for awards granted prior to January 1, 2006, over a period to the date the participant first became eligible for retirement, stock-based compensation would have decreased $0.4 million and $1 million for 2007 and 2006, respectively, and would have increased $1 million for 2005.

Total stock-based compensation expense (reflected in the caption "Administrative and general" on the consolidated statements of income) was $10 million, $11 million and $21 million for 2007, 2006 and 2005, respectively. The income tax benefit recognized in the income statement was $4 million, $4 million and $8 million for 2007, 2006 and 2005, respectively.

The following table illustrates the effect on net income if EME had used the fair-value accounting method for 2005.

	Year Ended December 31, 2005
	(in millions)
Net income, as reported	$ 442
Add: stock-based compensation expense using the intrinsic value accounting method—net of tax	13
Less: stock-based compensation expense using the fair value accounting method, net of tax	(10)
Pro forma net income	$ 445

Note 2. Restructuring Costs

During the first quarter of 2005, EME initiated a review of its domestic organization to better align its resources with its domestic business requirements. Management and organizational changes have been implemented to streamline EME's reporting relationships and eliminate its regional management structure. As a result of these changes, EME recorded charges of approximately $13 million (pre-tax) in 2005 for severance and related costs. These charges were included in administrative and general expense on EME's consolidated statement of income.

Note 3. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss), including discontinued operations, consisted of the following:

	Unrealized Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	Unrecognized Losses and Prior Service Costs, Net(2)	Accumulated Other Comprehensive Income (Loss)
		(in millions)		
Balance at December 31, 2005	$(210)	$ (1)	$ —	$(211)
Change for 2006	321	(3)	—	318
SFAS No. 158 adjustments(1)	—	4	(10)	(6)
Balance at December 31, 2006	111	—	(10)	101
Change for 2007	(171)	—	7	(164)
Balance at December 31, 2007	$ (60)	$ —	$ (3)	$ (63)

(1) Represents adjustments to initially apply SFAS No. 158 discussed in Note 11—Compensation and Benefit Plans.

(2) For further detail, see Note 11—Compensation and Benefit Plans.

Unrealized losses on cash flow hedges, net of tax, at December 31, 2007, included unrealized losses on commodity hedges related to Midwest Generation and EME Homer City futures and forward electricity contracts that qualify for hedge accounting. These losses arise because current forecasts of future electricity prices in these markets are greater than the contract prices. As EME's hedged positions for continuing operations are realized, approximately $3 million, after tax, of the net unrealized losses on cash flow hedges at December 31, 2007 are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized losses will decrease energy revenue recognized at market prices. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions. The maximum period over which a cash flow hedge is designated is through December 31, 2010.

Under SFAS No. 133, the portion of a cash flow hedge that does not offset the change in value of the transaction being hedged, which is commonly referred to as the ineffective portion, is immediately recognized in earnings. EME recorded net losses of approximately $41 million, $6 million and $65 million in 2007, 2006 and 2005, respectively, representing the amount of cash flow hedges' ineffectiveness for continuing operations, reflected in operating revenues in EME's consolidated income statements.

Note 4. Acquisitions and Consolidations

Transfer of Wind Projects from an Affiliate

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. The acquisition was accounted for as a transaction between entities under common control. As such, the assets and liabilities of the projects acquired were recorded at historical cost on the acquisition date for a net book value of approximately $76 million. The principal components of the net book value of assets and liabilities at April 1, 2006 are current assets ($8 million), property, plant and equipment, net ($156 million), other non-current assets ($42 million), deferred income ($56 million) and deferred income taxes ($59 million). EME's historical financial statements have been adjusted for all periods presented to reflect the acquisition as though

EME had ownership of such projects, including a distribution paid by Edison Capital to its parent in 2005. Summarized results of the projects acquired for periods presented prior to the acquisition date of April 1, 2006 are as follows:

	Three Months Ended March 31, 2006	Year Ended December 31, 2005
	(unaudited)	(in millions)
Total operating revenues	$ 4	$ 17
Income (loss) before income taxes	(1)	(3)
Benefit for income taxes	(3)	(13)
Income from continuing operations	2	10

Acquisitions

Wildorado Wind Project

On January 5, 2006, EME completed a transaction with Cielo Wildorado, G.P., LLC and Cielo Capital, L.P. to acquire a 99.9% interest in Wildorado Wind, L.P., which owns a 161 MW wind farm located in the panhandle of northern Texas, referred to as the Wildorado wind project. The acquisition included all development rights, title and interest held by Cielo in the Wildorado wind project, except for a small minority stake in the project retained by Cielo. The total purchase price was $29 million. This project started construction in April 2006 and commenced commercial operation during April 2007. The acquisition was accounted for utilizing the purchase method. The fair value of the Wildorado wind project was equal to the purchase price and as a result, the total purchase price was allocated to property, plant and equipment in EME's consolidated balance sheet.

San Juan Mesa Project

On December 27, 2005, EME completed a transaction with Padoma Project Holdings, LLC to acquire a 100% interest in the San Juan Mesa Wind Project, which owns a 120 MW wind power generation facility located in New Mexico, referred to as the San Juan Mesa wind project. The total purchase price was $156.5 million. The acquisition was funded with cash. The acquisition was accounted for utilizing the purchase method. The fair value of the San Juan Mesa wind project was equal to the purchase price and as a result, the entire purchase price was allocated to property, plant and equipment in EME's consolidated balance sheet. EME's consolidated statement of income reflected the operations of the San Juan Mesa project beginning January 1, 2006. The pro forma effects of the San Juan Mesa wind project acquisition on EME's consolidated financial statements were not material.

Consolidations

Variable Interest Entities

In December 2003, the FASB issued FIN 46(R). This Interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. Under this Interpretation, the primary beneficiary is the variable interest holder that absorbs a majority of expected losses; if no variable interest holder meets these criteria, then it is the variable interest holder that receives a majority of the expected residual returns. The primary beneficiary is required to consolidate the variable interest entity unless specific exceptions or exclusions are met.

Consolidation of Special Purpose Entities—

U.S. Wind Force is a development stage enterprise formed to develop wind projects in West Virginia, Pennsylvania and Maryland. In December 2006, a subsidiary of EME entered into a loan agreement with U.S. Wind Force to fund the redemption of a membership interest held by another party, repayment of loans, distributions to equity holders and future development of wind projects. In accordance with FIN 46(R), EME determined that it is the primary beneficiary and, accordingly, EME consolidated U.S. Wind Force at December 15, 2006. At December 31, 2007 and 2006, the assets consolidated included $10 million and $17 million of intangible assets, respectively, primarily related to project development rights. As project development is completed, the project development rights will be considered part of property, plant and equipment and depreciated over the estimated useful lives of the respective projects.

Consolidation of Wind Projects—

Effective March 31, 2004, three wind projects were consolidated and at December 31, 2005, two additional wind projects were consolidated in accordance with FIN 46(R). These projects were funded with nonrecourse debt totaling $24 million at December 31, 2007. Properties serving as collateral for these loans had a carrying value of $53 million and are classified as property, plant and equipment on EME's consolidated balance sheet at December 31, 2007.

Variable Interest Entities—

EME completed a review of the application of FIN 46(R) to its subsidiaries and affiliates and concluded that it had significant variable interests in variable interest entities as defined in this Interpretation. As of December 31, 2007, these entities consisted of five equity investments (the Big 4 projects and the Sunrise project) that had interests in natural gas-fired facilities with a total generating capacity of 1,782 MW. An operations and maintenance subsidiary of EME operates the Big 4 projects, but EME does not supply the fuel consumed or purchase the power generated by these facilities. EME determined that it is not the primary beneficiary in these entities; accordingly, EME continues to account for its variable interests on the equity method. EME's maximum exposure to loss in these variable interest entities is generally limited to its investment in these entities, which totaled $346 million as of December 31, 2007.

Note 5. Divestitures

Dispositions

On March 7, 2006, EME completed the sale of a 25% 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.

Discontinued Operations

Tri Energy Project

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project pursuant to a Purchase Agreement, dated December 15, 2004, by and between EME and IPM for approximately $20 million. EME recorded an impairment charge of approximately $5 million during the fourth quarter of 2004 related to the planned disposition of this investment. The sale of this investment had no significant effect on net income in the first quarter of 2005.

CBK Project

On January 10, 2005, EME sold its 50% equity interest in the CBK project pursuant to a Purchase Agreement, dated November 5, 2004, by and between EME and Corporacion IMPSA S.A. Proceeds from the sale were approximately $104 million. EME recorded a pre-tax gain on the sale of approximately $9 million during the first quarter of 2005.

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 £5 million (approximately $10 million) in 2007. The after-tax income attributable to the Lakeland project was $6 million, $85 million and $24 million for 2007, 2006 and 2005, 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).

Summarized Financial Information for Discontinued Operations

In accordance with SFAS No. 144, all the projects discussed above are classified as discontinued operations in the accompanying consolidated statements of income. Previously issued statements of operations have been restated to reflect discontinued operations reported subsequent to the original issuance date. Summarized results of discontinued operations are as follows:

	Years Ended December 31,		
	2007	**2006**	**2005**
		(in millions)	
Income (loss) before income taxes and minority interest	$ 3	$ 119	$ (20)
Provision (benefit) for income taxes	5	21	(44)
Income (loss) from operations of discontinued foreign subsidiaries	(2)	98	24
Gain on sale before income taxes	—	—	9
Gain on sale after income taxes	—	—	5

During the fourth quarter of 2006, EME recorded a tax benefit adjustment of $22 million, which resulted from resolution of a tax uncertainty pertaining to the ownership interest in a foreign project. EME's payment of $34 million during the second quarter of 2006 related to an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal resulted in a $3 million additional loss recorded in 2006. 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 and are included in "Provision (benefit) for income taxes" in the above table.

Note 6. Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates, generally 50% or less owned partnerships and corporations, are accounted for by the equity method. These investments are primarily in energy projects. The difference between the carrying value of these equity investments and the underlying equity in the net assets amounted to $13 million at December 31, 2007. The differences are being amortized over the life of the energy projects. The following table presents summarized financial information of the investments in unconsolidated affiliates:

	2007	2006
	(in millions)	
Investments in Unconsolidated Affiliates		
Equity investment	$ 375	$ 326
Cost investment	12	13
Loans receivable (payable)	—	28
Total	$ 387	$ 367

At December 31, 2007 and 2006, EME has a 38% ownership interest in a small biomass project that it accounts for under the cost method of accounting as it does not have a significant influence over the project's operating and financial activities. EME believes that the carrying amount at December 31, 2007 and 2006 was not impaired. EME's subsidiaries have provided loans or advances related to certain projects. The loans receivable at December 31, 2006 primarily consisted of a $26 million, 5% interest promissory note, interest payable semiannually, which was paid off in October 2007. The undistributed earnings of equity method investments were $38 million in 2007 and $43 million in 2006.

The following table presents summarized financial information of the remaining investments in unconsolidated affiliates accounted for by the equity method:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Revenues	$1,464	$1,574	$1,830
Expenses	1,070	1,207	1,452
Net income	$ 394	$ 367	$ 378

	December 31,	
	2007	2006
	(in millions)	
Current assets	$ 440	$ 490
Noncurrent assets	814	1,000
Total assets	$1,254	$1,490
Current liabilities	$ 250	$ 330
Noncurrent liabilities	299	572
Equity	705	588
Total liabilities and equity	$1,254	$1,490

For 2006 and 2005, the summarized financial information included the Doga project. Effective March 31, 2007, EME accounted for its ownership in the Doga project on the cost method as accumulated distributions exceeded accumulated earnings. Therefore, the Doga project is not included in the balances at December 31, 2007 and only three months for the year ended December 31, 2007. EME has not estimated the fair value of cost method investments as quoted market prices are not available and the determination of fair value is highly subjective and cannot be readily ascertained.

The majority of noncurrent liabilities are comprised of project financing arrangements that are non-recourse to EME.

The following table presents, as of December 31, 2007, the investments in unconsolidated affiliates accounted for by the equity method that represent at least five percent (5%) of EME's income before tax or in which EME has an investment balance greater than $50 million.

Unconsolidated Affiliates	Location	Investment at December 31, 2007	Ownership Interest at December 31, 2007	Operating Status
		(in millions)		
Sunrise	Fellows, CA	$127	50%	Operating gas-fired facility
Watson	Carson, CA	74	49%	Operating cogeneration facility
Sycamore	Bakersfield, CA	58	50%	Operating cogeneration facility

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.

Note 7. Property, Plant and Equipment

Property, plant and equipment consist of the following:

	December 31,	
	2007	2006
	(in millions)	
Power plant facilities	$ 2,857	$ 2,402
Leasehold improvements	110	100
Emission allowances	1,305	1,305
Construction in progress	587	365
Equipment, furniture and fixtures	82	99
Capitalized leased equipment	1	1
	4,942	4,272
Less accumulated depreciation and amortization	1,053	981
Net property, plant and equipment	$ 3,889	$ 3,291

The power sales agreements of certain wind projects qualify as operating leases under EITF No. 01-8, "Determining Whether an Arrangement Contains a Lease," and SFAS No. 13, "Accounting for Leases." The carrying amount and related accumulated depreciation of the property of these wind projects totaled $559 million and $28 million, respectively, at December 31, 2007. EME records rental income from wind projects that are accounted for as operating leases as electricity is delivered at rates defined in power sales agreements. Revenue from these power sales agreements were $24 million in 2007 and $10 million in 2006.

In connection with Midwest Generation's financing activities, EME has given a first priority security interest in substantially all the coal-fired generating plants owned by Midwest Generation and the assets relating to those plants and receivables of EMMT directly related to Midwest Generation's hedging activities. The amount of assets pledged or mortgaged totaled approximately $2.8 billion at December 31, 2007. In addition to these assets, Midwest Generation's membership interests and the capital stock of Edison Mission Midwest Holdings were pledged. Emission allowances have not been pledged.

Asset Retirement Obligations

Effective January 1, 2003, EME adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

In March 2005, the FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations," an interpretation of SFAS No. 143. This interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. This interpretation became effective as of December 31, 2005 for EME. EME identified conditional AROs related to asbestos removal and disposal costs at its owned Illinois Plants (buildings and power plant facilities) and retired structures leased at the Powerton Station, and recorded a $1 million, after tax, charge as a cumulative effect of a change in accounting. EME has not recorded a liability related to the owned structures because it cannot reasonably estimate fair value of the obligation at this time. The range of time over which EME may settle this obligation in the future (demolition or other method) is sufficiently large to not allow for the use of expected present value techniques.

EME recorded a liability representing expected future costs associated with site reclamations, facilities dismantlement and removal of environmental hazards as follows:

	2007	2006	2005
		(in millions)	
Beginning balance	$ 11	$ 7	$ 5
Cumulative effect of accounting change	—	—	2
Obligation incurred	7	1	—
Liabilities settled during the period	(3)	(1)	—
Accretion expense	1	1	—
Change in estimates	—	3	—
Ending balance	$ 16	$ 11	$ 7

The pro forma net income and liability impacts of adopting FIN 47 are immaterial.

Note 8. Financial Instruments

Long-Term Obligations

Long-term obligations include both corporate debt and non-recourse project debt, whereby lenders rely on specific project assets to repay such obligations. At December 31, 2007, recourse debt to EME totaled $3.7 billion and non-recourse project debt totaled $110 million. Long-term obligations consist of the following:

	December 31,	
	2007	2006
	(in millions)	
Recourse		
EME (parent only)		
Senior Notes, net		
due 2009 (7.73%)	$ 13	$ 599
due 2013 (7.50%)	500	500
due 2016 (7.75%)	500	500
due 2017 (7.00%)	1,200	—
due 2019 (7.20%)	800	—
due 2027 (7.625%)	700	—
Obligations to Affiliates	—	78

	December 31,	
	2007	2006
	(in millions)	
Non-recourse		
Due to EME Funding Corp. – Long-Term Obligation due 2008 (7.33%)	8	51
EME CP Holdings Co.		
Note Purchase Agreement due 2015 (7.31%)	72	76
Midwest Generation		
Second Priority Senior Secured Notes due 2034 (8.75%)	—	1,000
Credit Agreement due 2011 (LIBOR+1.50%)		
(6.94% at 12/31/06)	—	330
Other	30	33
Subtotal	$ 3,823	$ 3,167
Less current maturities of long-term obligations	17	132
Total	$ 3,806	$ 3,035

Refinancing

Senior Notes

In 2006, EME issued $500 million of its 7.50% senior notes due 2013 and $500 million of its 7.75% senior notes due 2016. EME used the net proceeds of the offering, together with cash on hand, to purchase its 10% senior notes due 2008 and 9.875% senior notes due 2011. EME recorded a total pre-tax loss of $146 million ($90 million after tax) on early extinguishment of debt in 2006.

In 2007, EME issued $1.2 billion of its 7.00% senior notes due 2017, $800 million of its 7.20% senior notes due 2019 and $700 million of its 7.625% senior notes due 2027. EME pays 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 and 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; 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. EME recorded a total pre-tax loss of $160 million ($98 million after tax) on early extinguishment of debt in 2007.

The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, of the senior notes plus a "make-whole" premium. The senior notes are EME's senior unsecured obligations, ranking equal in right of payment to all of EME's existing and future senior unsecured indebtedness, and will be senior to all of 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 the existing and future liabilities of EME's subsidiaries are effectively senior to the senior notes.

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.

Credit Agreement

During 2007, EME amended its existing $500 million secured credit facility maturing on June 15, 2012, increasing the total borrowings available thereunder to $600 million, and subject to the satisfaction of conditions as set forth in the secured credit facility, EME is permitted to increase the amount available under the secured credit facility to an amount that does not exceed 15% of EME's consolidated net tangible assets, as defined in the secured credit facility. Loans made under this credit facility bear interest, at EME's election, at either LIBOR (which is based on the interbank Eurodollar market) or the base rate (which is calculated as the higher of Citibank, N.A.'s publicly announced base rate and the federal funds rate in effect from time to time plus 0.50%) plus, in both cases, an applicable margin. The applicable margin depends on EME's debt ratings. At December 31, 2007, EME had no borrowings outstanding and $93 million of letters of credit outstanding under this credit facility. The credit facility contains financial covenants which require EME to maintain a minimum interest coverage ratio and a maximum corporate debt to corporate capital ratio. A failure to meet a ratio threshold could trigger other provisions, such as mandatory prepayment provisions or restrictions on dividends. At December 31, 2007, EME met both these ratio tests.

As security for its obligations under this credit facility, EME pledged its ownership interests in the holding companies through which it owns its interests in the Illinois Plants, the Homer City facilities, the Westside projects and the Sunrise project. EME also 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 proceeds unless an event of default occurs under the credit facility.

During 2007, Midwest Generation also amended and restated its existing $500 million senior secured working capital facility. Loans made under this working capital facility bear interest at LIBOR + 0.55%. The working capital facility matures in 2012, with an option to extend for up to two years. The working capital facility contains financial covenants which require Midwest Generation to maintain a debt to capitalization ratio of no greater than 0.60 to 1. At December 31, 2007, the debt to capitalization ratio was 0.23 to 1. Midwest Generation uses its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation can also support its hedging activities by granting liens to eligible hedge counterparties. As of December 31, 2007, Midwest Generation had no borrowings outstanding and $3 million of letters of credit had been utilized under the working capital facility.

Annual Maturities on Long-Term Obligations

Annual maturities on long-term debt at December 31, 2007, for the next five years are summarized as follows: 2008—$17 million; 2009—$25 million; 2010—$12 million; 2011—$14 million; and 2012—$15 million.

Standby Letters of Credit

As of December 31, 2007, standby letters of credit aggregated to $97 million and were scheduled to expire as follows: $89 million in 2008 and $8 million in 2009.

Fair Values of Non-Derivative Financial Instruments

The carrying amount of cash and cash equivalents, trade accounts receivables and payables contained in EME's consolidated balance sheet approximates fair value. The following table summarizes the carrying amounts and fair values for outstanding non-derivative financial instruments (in millions):

	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Instruments				
Non-derivatives:				
Long-term obligations	$ 3,823	$ 3,782	$ 3,167	$ 3,494

In assessing the fair value of EME's long-term obligations, EME uses quoted market prices.

Note 9. Risk Management and Derivative Financial Instruments

EME's risk management policy allows for the use of derivative financial instruments to limit financial exposure on EME's investments and to manage exposure from fluctuations in electricity, capacity and fuel prices, emission allowances, transmission rights, and interest rates for both trading and non-trading purposes.

Commodity Price Risk Management

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. EME uses "earnings at risk" to identify, measure, monitor and control its overall market risk exposure with respect to hedge positions of the Illinois Plants, the Homer City facilities, and the merchant wind projects, and "value at risk" to identify, measure, monitor and control its overall risk exposure in respect of its trading positions. The use of these measures 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, and earnings at risk measures the potential change in value of an asset or position, in each case over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of these measures and relying on a single type of risk measurement tool, EME supplements these approaches 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.

In order to provide more predictable earnings and cash flow, EME may hedge a portion of the electric output of its merchant plants. When appropriate, EME manages the spread between the electric prices and fuel prices, and uses forward contracts, swaps, futures, or options contracts to achieve those objectives.

Interest Rate Risk Management

Interest rate changes affect the cost of capital needed to operate EME's 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 EME's project financings.

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.

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.

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 51%, 58% and 69% of EME's consolidated operating revenues for the years ended December 31, 2007, 2006 and 2005, respectively. Moody's rates PJM's senior unsecured debt Aa3. PJM, an ISO 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 December 31, 2007, EME's account receivable due from PJM was $82 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 for the year ended December 31, 2007. Commonwealth Edison's senior unsecured debt rating was downgraded below investment grade by S&P in June 2007 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 December 31, 2007, EME's account receivable due from Commonwealth Edison was $20 million.

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):

	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Commodity price:				
Electricity	$ (137)	$ (137)	$ 184	$ 184

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 the commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors.

EME classifies unrealized gains and losses from energy contracts as part of operating revenues. The following table summarizes unrealized gains (losses) from non-trading activities for the three-year period ended December 31, 2007:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Non-qualifying hedges			
Illinois Plants	$ (14)	$ 28	$ (17)
Homer City	(1)	2	(1)
Ineffective portion of cash flow hedges			
Illinois Plants	(11)	2	(2)
Homer City	(9)	33	(40)
Total unrealized gains (losses)	$ (35)	$ 65	$ (60)

Energy Trading

EME engages in energy trading activities in markets where its merchant power plants are located. EME trades power, fuel and transmission using products available over the counter, through exchanges and from ISOs. Energy trading activity is limited by EME's risk management policies, including a limit on value at risk.

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

	December 31, 2007		December 31, 2006	
	Assets	Liabilities	Assets	Liabilities
Electricity	$ 141	$ 9	$ 313	$ 207
Other	—	—	5	—
Electricity	$ 141	$ 9	$ 318	$ 207

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.

EME recorded net gains of approximately $149 million, $137 million and $202 million in 2007, 2006 and 2005, respectively, arising from energy trading activities reflected in operating revenues in EME's consolidated income statement. In accordance with Emerging Issues Task Force No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," EME netted 4.1 million MWh and 4.3 million MWh of sales and purchases of physically settled, gross purchases and sales during 2007 and 2006, respectively.

Note 10. Income Taxes

Current and Deferred Taxes

The provision for income taxes is comprised of the following:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Continuing Operations:			
Current			
Federal	$ 138	$ 65	$ 231
State	14	16	39
Foreign	—	(1)	(1)
Total current	152	80	269
Deferred			
Federal	$ 60	$ 87	$ (50)
State	7	22	(11)
Total deferred	67	109	(61)
Provision for income taxes from continuing operations	219	189	208
Discontinued operations	5	22	(40)
Change in accounting	—	—	(1)
Total	$ 224	$ 211	$ 167

The components of income (loss) before income taxes and minority interest applicable to continuing operations, discontinued operations, and cumulative effect of change in accounting are as follows:

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Continuing Operations			
U.S.	$ 634	$ 503	$ 614
Foreign	—	1	8
Total, continuing operations	634	504	622
Discontinued operations	3	120	(11)
Change in accounting	—	—	(2)
Total	$ 637	$ 624	$ 609

Variations from the 35% federal statutory rate for income from continuing operations are as follows:

	Years Ended December 31,		
	2007	2006	2005
	(in millions)		
Provision for federal income taxes at statutory rate	$ 222	$ 176	$ 218
Increase (decrease) in taxes from:			
State tax, net of federal benefit	26	23	20
Taxes on foreign operations at different rates	2	6	(4)
Resolution of IRS audit issue	—	—	(11)
Federal production tax credits	(27)	(12)	(8)
Other	(4)	(4)	(7)
Total provision for income taxes from continuing operations	$ 219	$ 189	$ 208
Effective tax rate	34%	37%	33%

The components of the net accumulated deferred income tax liability are:

	December 31,	
	2007	2006
	(in millions)	
Deferred tax assets		
Accrued charges	$ 87	$ 86
Derivative assets	69	—
Deferred income	5	5
Total	161	91
Deferred tax liabilities		
Basis differences	$ 481	$ 395
Derivative liabilities	—	84
Deferred investment tax credit	9	10
State taxes	—	3
Other	1	5
Total	491	497
Deferred tax liabilities and tax credits, net	$ 330	$ 406
Classification of accumulated deferred income taxes:		
Included in current assets	$ 21	$ —
Included in current liabilities	$ —	$ 59
Included in non-current liabilities	$ 351	$ 347

There were no federal or state loss carryforwards at December 31, 2007.

Accounting for Uncertainty in Income Taxes

The following table provides a reconciliation of unrecognized tax benefits:

	(in millions)
Balance, January 1, 2007	$ 140
Tax positions taken during the current year	
Increases	6
Decreases	—
Tax positions taken during a prior year	
Increases	—
Decreases	8
Decreases for settlements during the period	2
Balance, December 31, 2007	$ 136

The total amount of unrecognized tax benefits as of December 31, 2007 and the date of adoption that, if recognized, would affect the effective tax rate was $114 million and $119 million, respectively.

The total amount of accrued interest and penalties was $49 million and $41 million as of December 31, 2007 and the date of adoption, respectively. The total amount of interest expense and penalties recognized in income tax expense was $8 million for 2007. 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. It is reasonably possible that EME could reach a settlement with the Internal Revenue Service to all or a portion of the unrecognized tax benefits through tax year 2002 within the next 12 months. EME believes that it is reasonably possible that unrecognized tax benefits could be reduced by an amount up to $37 million within the next 12 months.

Note 11. Compensation and Benefit Plans

Employee Savings Plan

A 401(k) plan is maintained to supplement eligible United States employees' retirement income. The plan received contributions from EME of $6 million each in 2007, 2006 and 2005.

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 plan and other postretirement plans as assets or liabilities in their balance sheet; the assets or liabilities are offset through other comprehensive income (loss). 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.

Pension Plans

Noncontributory defined benefit pension plans (the non-union plan has a cash balance feature) cover most employees meeting minimum service requirements.

The expected contributions (all by the employer) are approximately $21 million for the year ended December 31, 2008. This amount is subject to change depending on the funded status at year-end and the tax deductible funding limitations.

The fair value of plan assets is determined primarily by quoted market prices.

Information on plan assets and benefit obligations is shown below:

	Years Ended December 31, 2007	Years Ended December 31, 2006
	(in millions)	
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 184	$ 159
Service cost	16	16
Interest cost	10	9
Actuarial loss (gain)	(7)	3
Benefits paid	(7)	(6)
Intercompany transfers	—	3
Projected benefit obligation at end of year	$ 196	$ 184
Change in plan assets		
Fair value of plan assets at beginning of year	$ 115	$ 91
Actual return on plan assets	10	15
Employer contributions	16	13
Benefits paid	(7)	(6)
Intercompany transfers	—	2
Fair value of plan assets at end of year	$ 134	$ 115
Funded status at end of year	$ (62)	$ (69)
Amounts recognized in consolidated balance sheets:		
Long-term liabilities	$ 62	$ 69
Amounts recognized in accumulated other comprehensive income (loss):		
Prior service cost	$ 1	$ 1
Net loss (gain)	(3)	6
Accumulated benefit obligation at end of year	$ 166	$ 156

	Years Ended December 31,	
	2007	2006
	(in millions)	
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 196	$ 163
Accumulated benefit obligation	166	142
Fair value of plan assets	134	100
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	6.25%	5.75%
Rate of compensation increase	5.0%	5.0%

Expense components and other amounts recognized in other comprehensive income (loss)

Expense components:

	Years Ended December 31,		
	2007	2006	2005
	(in millions)		
Service cost	$16	$16	$16
Interest cost	11	9	8
Expected return on plan assets	(9)	(7)	(6)
Net amortization	1	1	1
Total expense	$19	$19	$19

Other changes in plan assets and benefit obligations recognized in other comprehensive loss:

	Year Ended December 31, 2007
	(in millions)
Net gain	$ (11)
Prior service credit	(1)
Amortization of net loss	(1)
Total in other comprehensive loss	$ (13)
Total in expense and other comprehensive loss	$ 6

The estimated amortization amounts reclassified from other comprehensive loss for 2008 are $0.1 million for prior service costs and $1 million for net loss.

	Years Ended December 31,		
	2007	2006	2005
Weighted-average assumptions:			
Discount rate	5.75%	5.5%	5.5%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected long-term return on plan assets	7.5%	7.5%	7.5%

The following benefit payments, which reflect expected future service, are expected to be paid:

Years Ending December 31,	(in millions)
2008	$ 8
2009	9
2010	10
2011	12
2012	14
2013-2017	96

Asset allocations are:

	Target for 2008	December 31, 2007	December 31, 2006
United States equity	45%	47%	47%
Non-United States equity	25%	25%	26%
Private equity	4%	2%	2%
Fixed income	26%	26%	25%

Postretirement Benefits Other Than Pensions

Most non-union employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits. Eligibility depends on a number of factors, including the employee's hire date.

The expected contributions (all by the employer) for the postretirement benefits other than pensions trust are $2 million for the year ended December 31, 2008. This amount is subject to change depending on the funded status at year-end and the tax deductible funding limitations.

Information on plan assets and benefit obligations is shown below:

	Years Ended December 31, 2007	Years Ended December 31, 2006
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 76	$ 72
Service cost	3	2
Interest cost	5	4
Actuarial loss (gain)	1	(3)
Benefits paid	(2)	(1)
Intercompany transfers	—	2
Benefit obligation at end of year	$ 83	$ 76

	Years Ended December 31,	
	2007	2006
	(in millions)	
Change in plan assets		
Fair value of plan assets at beginning of year	$ —	$ —
Employer contributions	1	1
Benefits paid	(1)	(1)
Fair value of plan assets at end of year	$ —	$ —
Funded status at end of year	$ (83)	$ (76)
Amounts recognized in balance sheets:		
Long-term liabilities	$ 83	$ 76
Amounts recognized in accumulated other comprehensive income (loss):		
Prior service credit	$ (7)	$ (9)
Net loss	16	17
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	6.25%	5.75%
Assumed health care cost trend rates:		
Rate assumed for following year	9.25%	9.25%
Ultimate rate	5.0%	5.0%
Year ultimate rate reached	2015	2011

Expense components and other amounts recognized in other comprehensive income (loss)

Expense components:

	Years Ended December 31,		
	2007	2006	2005
	(in millions)		
Service cost	$ 2	$ 2	$ 2
Interest cost	5	4	4
Amortization of prior service costs	(2)	(2)	(2)
Amortization of net loss	2	1	2
Total expense	$ 7	$ 5	$ 6

Other changes in plan assets and benefit obligations recognized in other comprehensive loss:

	Year Ended December 31, 2007
	(in millions)
Net gain	$ (1)
Prior service cost	2
Amortization of prior service cost	2
Amortization of net loss	(2)
Total in other comprehensive loss	$ 1
Total in expense and other comprehensive loss	$ 8

The estimated amortization amounts reclassified from other comprehensive loss for 2008 are $(2) million for prior service credit and $1 million for net loss.

	Years Ended December 31,		
	2007	2006	2005
Weighted-average assumptions used to determine expense:			
Discount rate	5.75%	5.5%	5.75%
Assumed health care cost trend rates:			
Current year	9.25%	10.25%	10.0%
Ultimate rate	5.0%	5.0%	5.0%
Year ultimate rate reached	2015	2011	2010

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2007, by $13 million and annual aggregate service and interest costs by $1 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2007, by $12 million and annual aggregate service and interest costs by $1 million.

The following benefit payments are expected to be paid:

Years ended December 31,	Before Subsidy	Net
	(in millions)	
2008	$ 2	$ 2
2009	2	2
2010	3	3
2011	3	3
2012	4	4
2013-2017	29	28

Discount Rate

The discount rate enables EME to state expected future cash flows at a present value on the measurement date. EME selects its discount rate by performing a yield curve analysis. This analysis determines the equivalent discount rate on projected cash flows, matching the timing and amount of expected benefit payments. Three yield curves were considered: two corporate yield curves (Citigroup and AON) and a curve based on treasury rates (plus 90 basis points). EME also compared the yield curve analysis against the Moody's AA Corporate bond rate.

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. EME employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is controlled through diversification among multiple asset classes, managers, styles, and securities. Plan, asset class and individual manager performance is measured against targets. EME also monitors the stability of its investments managers' organizations.

Allowable investment types include:

- *United States Equity:* Common and preferred stocks of large, medium, and small companies which are predominantly United States-based.
- *Non-United States Equity:* Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.
- *Private Equity:* Limited partnerships that invest in non-publicly traded entities.
- *Fixed Income:* Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities, mortgage backed securities and corporate debt obligations. A small portion of the fixed income position may be held in debt securities that are below investment grade.

Permitted ranges around asset class portfolio weights are plus or minus 5%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to approach fully invested portfolio positions. Where authorized, a few of the plans' investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets for United States Plans

The overall expected long-term rate of return on assets assumption is based on the target asset allocation for plan assets and capital markets return forecasts for asset classes employed. A portion of postretirement benefits other than pensions trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

The estimated total return for fixed income is based on an equilibrium yield for intermediate United States government bonds plus a premium for exposure to non-government bonds in the broad fixed income market. The equilibrium yield is based on analysis of historic data and is consistent with experience over various economic environments. The premium of the broad market over United States government bonds is a historic average premium. The estimated rate of return for equity is estimated to be a 3% premium over the estimated total return of intermediate United States government bonds. This value is determined by combining estimates of real earnings growth, dividend yields and inflation, each of which was determined using historical analysis. The rate of return for private equity is estimated to be a 5% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Stock-Based Compensation

Stock Options

Under various plans, EME has granted stock options at exercise prices equal to the average of the high and low price, and beginning in 2007, at the closing price at the grant date, EME may grant stock options and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants, as discussed in Note 1—Stock-Based Compensation. Stock-based compensation associated with stock options was $6 million and $8 million in 2007 and 2006, respectively. Under prior accounting rules, there was no comparable expense recognized for the same period in 2005. See Note 1—Stock-Based Compensation, for further discussion.

Stock options granted in 2003 through 2006 accrue dividend equivalents for the first five years of the option term. Stock options granted in 2007 have no dividend equivalent rights. Unless transferred to nonqualified deferral plan accounts, dividend equivalents accumulate without interest. Dividend equivalents are paid only on options that vest, including options that are unexercised. Dividend equivalents are paid in cash after the vesting date. Edison International has discretion to pay certain dividend equivalents in shares of Edison International common stock. Additionally, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

The fair value for each option granted was determined as of the date of grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table.

Years ended December 31,	2007	2006	2005
Expected terms (in years)	7.5	9-10	9-10
Risk-free interest rate	4.6% to 4.8%	4.3% to 4.7%	4.1% to 4.3%
Expected dividend yield	2.1% to 2.5%	2.3% to 2.8%	2.1% to 3.1%
Weighted-average expected dividend yield	2.4%	2.4%	3.1%
Expected volatility	16% to 17%	16% to 17%	15% to 20%
Weighted-average volatility	16.5%	16.3%	19.5%

The expected term represents the period of time for which the options are expected to be outstanding and is based on historical exercise and post-vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a 52-week historical average of the 10-year semi-annual coupon U.S. Treasury note. In 2006, expected volatility is based on the historical volatility of Edison international's common stock for the most recent 36 months. Prior to January 1, 2006, expected volatility was based on the median of the most recent 36 months historical volatility of peer companies because Edison International's historical volatility was impacted by the California energy crisis.

A summary of the status of Edison International's stock options granted to EME employees is as follows:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding, December 31, 2006	3,014,145	$25.52		
Granted	373,592	$47.72		
Transferred to affiliates	6,378	$41.63		
Forfeited	(15,441)	$44.23		
Exercised	(941,182)	$16.68		
Outstanding, December 31, 2007	2,437,492	$30.82		
Vested and expected to vest at December 31, 2007	2,333,692	$30.47	6.68	$58,418,146
Exercisable at December 31, 2007	1,144,523	$23.60	5.75	$36,513,145

The weighted-average grant-date fair value of options granted during 2007, 2006 and 2005 was $11.36, $14.44 and $11.74, respectively. The total intrinsic value of options exercised was $32 million during 2007 and $18 million during each 2006 and 2005. At December 31, 2007, there was $6 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 2007, 2006 and 2005 was $6 million, $8 million and $5 million, respectively.

The amount of cash used by Edison International to settle stock options exercised by EME employees was $49 million, $33 million and $31 million for 2007, 2006 and 2005, respectively. Cash received by Edison International from options exercised by EME employees for 2007, 2006 and 2005 was $19 million, $15 million and $14 million, respectively. The estimated tax benefit from options exercised was $11 million for 2007 and $7 million for each 2006 and 2005.

Performance Shares

A target number of contingent performance shares were awarded to executives in January 2005, March 2006 and March 2007, and vest at the end of December 2007, 2008 and 2009, respectively. Performance shares awarded in 2005 and 2006 accrue dividend equivalents which accumulate without interest and will be payable in cash following the end of the performance period when the performance shares are paid. Edison International has discretion to pay certain dividend equivalents in Edison International common stock. Performance shares awarded in 2007 contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's common stock performance relative to the performance of a specified group of companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Dividend equivalents will be adjusted to correlate to the actual number of performance shares paid. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants, as discussed in Note 1—Stock-Based Compensation. Stock-based compensation associated with performance shares was $3 million, $3 million and $15 million for 2007, 2006 and 2005, respectively. The amount of cash used to settle performance shares classified as equity awards was $5 million, $10 million and $0.1 million for 2007, 2006 and 2005, respectively.

The performance shares' fair value is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires a risk-free interest rate and an expected volatility rate assumption. The risk-free interest rate is based on a 52-week historical average of the three-year semi-annual coupon U.S. Treasury note and is used as proxy for the expected return for the specified group of companies. Volatility is based on the historical volatility of Edison International's common stock for the recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

Edison International's risk-free interest rate used to determine the grant date fair values for the 2007, 2006 and 2005 performance shares classified as share-based equity awards was 4.8%, 4.1% and 2.7%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2007, 2006 and 2005 performance shares classified as share-based equity awards was 16.5%, 16.2% and 27.7%, respectively. The portion of performance shares classified as share-based liability awards are revalued at each reporting period. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2007 was 4.3% and 17.1%, respectively.

The total intrinsic value of performance shares settled during 2007, 2006 and 2005 was $12 million, $19 million and $8 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2007, 2006 and 2005 of $4 million, $8 million and $4 million, respectively. At December 31, 2007, there was $1 million (based on the December 31, 2007 fair value of performance shares classified as liability awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of less than two years. The fair value of performance shares vested during 2007, 2006 and 2005 was $4 million, $7 million and $11 million, respectively.

A summary of the status of Edison International nonvested performance shares granted to EME employees and classified as equity awards is as follows:

	Performance Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2006	42,681	$ 48.65
Granted	14,334	58.01
Forfeited	(351)	56.77
Paid out	(26,560)	46.09
Nonvested at December 31, 2007	30,104	$ 55.26

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2006 and 2005 was $52.86 and $46.09, respectively.

A summary of the status of Edison International nonvested performance shares granted to EME employees and classified as liability awards (the current portion is reflected in the caption "Accrued liabilities" and the long-term portion is reflected in "Other long-term liabilities" on the consolidated balance sheets) is as follows:

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2006	42,709	
Granted	14,349	
Forfeited	(351)	
Paid out	(26,570)	
Nonvested at December 31, 2007	30,137	$ 44.90

Note 12. Commitments and Contingencies

Lease Commitments

EME leases office space, property and equipment under noncancelable lease agreements that expire in various years through 2030.

Future minimum payments for operating leases at December 31, 2007 are:

Years Ending December 31,	Operating Leases (in millions)
2008	$ 363
2009	359
2010	347
2011	329
2012	328
Thereafter	2,382
Total future commitments	$ 4,108

The minimum commitments do not include contingent rentals with respect to the wind projects which may be paid under certain leases on the basis of a percentage of sales calculation if this is in excess of the stipulated minimum amount.

Operating lease expense amounted to $203 million in 2007 and $201 million in both 2006 and 2005.

Sale-Leaseback Transactions

On December 7, 2001, a subsidiary of EME completed a sale-leaseback of EME's Homer City facilities to third-party lessors for an aggregate purchase price of $1.6 billion, consisting of $782 million in cash and assumption of debt (the fair value of which was $809 million). Under the terms of the 33.67-year leases, EME's subsidiary is obligated to make semi-annual lease payments on each April 1 and October 1. If a lessor intends to sell its interest in the Homer City facilities, EME has a right of first refusal to acquire the interest at fair market value. Minimum lease payments (included in the table above) are $152 million in 2008, $151 million in 2009, $155 million in 2010, $160 million in 2011 and

$160 million in 2012, and the total remaining minimum lease payments are $1.7 billion. The gain on the sale of the facilities has been deferred and is being amortized over the term of the leases.

On August 24, 2000, a subsidiary of EME completed a sale-leaseback of EME's Powerton and Joliet power facilities located in Illinois to third-party lessors for an aggregate purchase price of $1.4 billion. Under the terms of the leases (33.75 years for Powerton and 30 years for Joliet), EME's subsidiary makes semi-annual lease payments on each January 2 and July 2, which began January 2, 2001. EME guarantees its subsidiary's payments under the leases. If a lessor intends to sell its interest in the Powerton or Joliet power facility, EME has a right of first refusal to acquire the interest at fair market value. Minimum lease payments (included in the table above) are $185 million in 2008 and 2009, $170 million in 2010, $151 million in 2011, and $151 million in 2012, and the total remaining minimum lease payments are $639 million. The gain on the sale of the power facilities has been deferred and is being amortized over the term of the leases.

Other Commitments

Capital Improvements

At December 31, 2007, EME's subsidiaries had firm commitments to spend approximately $249 million in 2008 and $4 million in 2009 on capital and construction expenditures. The majority of these expenditures relate to the construction of wind 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, 2007, EME had entered into agreements with vendors securing 483 wind turbines (1,076 MW) with remaining commitments of $481 million in 2008, $540 million in 2009 and $49 million in 2010. At December 31, 2007 and 2006, EME had recorded wind turbine deposits of $189 million and $144 million, respectively, included in other long-term assets in its consolidated balance sheet.

In addition, EME had 30 wind turbines (90 MW) in temporary storage to be used for future wind projects with remaining commitments of $3 million in 2008. At December 31, 2007, EME had recorded $84 million related to these wind turbines included in other long-term assets in its consolidated balance sheet.

Fuel Supply Contracts

At December 31, 2007, Midwest Generation and EME Homer City had fuel purchase commitments with various third-party suppliers. Based on the contract provisions, which consist of fixed prices, subject to adjustment clauses, these minimum commitments are currently estimated to aggregate $939 million in the next five years summarized as follows: 2008—$440 million; 2009—$328 million; 2010—$153 million; 2011—$9 million; and 2012—$9 million.

Gas Transportation Agreements

At December 31, 2007, EME had a contractual commitment to transport natural gas. EME's share of the commitment to pay minimum fees under its gas transportation agreement, which has a remaining contract length of 10 years, is currently estimated to aggregate $40 million in the next five years, $8 million each year, 2008 through 2012.

Coal Transportation Agreements

At December 31, 2007, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities. 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. Based on the committed coal volumes in the fuel supply contracts described above, these minimum commitments are currently estimated to aggregate $568 million in the next three years, summarized as follows: 2008—$245 million; 2009—$160 million; and 2010—$163 million.

Other Contractual Obligations

At December 31, 2007, EME and its subsidiaries were party to a long-term power purchase contract, a coal cleaning agreement, turbine operations and maintenance agreements, and agreements for the purchase of limestone and ammonia with various third parties. These minimum commitments are currently estimated to aggregate $82 million in the next five years: $19 million in 2008, $23 million in 2009, $24 million in 2010, $12 million in 2011 and $4 million in 2012.

Guarantees and Indemnities

EME and certain of its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, guarantees of debt and indemnifications.

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 continues 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 had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2009. 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 207 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2007. Midwest Generation had recorded a $54 million and $65 million liability at December 31, 2007 and 2006, respectively, related to this matter.

Midwest Generation engaged an independent actuary in 2004 to complete an estimate of future losses. Based on the actuary's analysis, Midwest Generation recorded an undiscounted liability for its indemnity for future asbestos claims through 2045. During the fourth quarter of 2007, the actuary report was updated and the liability reduced by $9 million. 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 no asbestos claims will be filed after 2044.

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 December 31, 2007 and 2006, EME had recorded a liability of $101 million and $95 million, respectively, 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. At December 31, 2007, EME had recorded a liability of $12 million related to these matters.

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. The obligations under this indemnification agreement as of December 31, 2007, if payment were required, would be $73 million. EME has not recorded a liability related to this indemnity.

Contingencies

FERC Notice Regarding Investigatory Proceeding against EMMT

In 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 EPAct 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. Discussions to date have been constructive and may lead to a settlement agreement acceptable to both parties. Should these discussions not result in a settlement and a formal proceeding 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 in the bidding practices that it employed, and intends to contest vigorously any allegation of violation.

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 FPA.

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 under separate qualifying facility contracts. As a seller into the California Markets, Midway-Sunset is potentially liable for refunds to entities that purchased in those markets.

In December 2007, Midway-Sunset and other parties to the proceeding entered into a settlement and release of claims agreement with respect to the refund claims, which is currently pending before the

FERC. Concurrently with the execution of the settlement and release of claims agreement, Midway-Sunset, SCE and PG&E entered into an agreement pursuant to which PG&E and SCE have agreed to reimburse Midway-Sunset, on a pro-rated basis, for refund liability resulting from sales made into the California Markets on their behalf, and PG&E has also agreed to pay to Midway-Sunset amounts outstanding for qualifying facility power sold by Midway-Sunset to PG&E and deemed delivered on its behalf prior to PG&E's declaration of bankruptcy. Midway-Sunset expects to receive approximately $1 million as a result of these transactions.

Settlement with Illinois Attorney General

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.

Legal actions, including a complaint at the FERC by the Illinois Attorney General and two class action lawsuits, were instituted against successful participants in the 2006 Illinois power procurement auction, including EMMT. 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. Enacting legislation for the settlement was signed on August 28, 2007.

As part of the settlement, Midwest Generation 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, all auction-related complaints filed by the Illinois Attorney General at the FERC, the Illinois Commerce Commission and in the Illinois courts were dismissed and the legislature enacted a rate relief plan.

Midwest Generation made a payment of $7.5 million in September 2007 and is obligated to make 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, Illinois imposes an electric rate freeze or an additional tax on generators. EME records the payments made under this agreement as an expense when paid.

Midwest Generation Potential Environmental Proceeding

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990's and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement 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 CAA, 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 CAA. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. As a result, Midwest Generation is investigating the claims made by the US EPA in the NOV and has identified several defenses which it will raise if the government files suit. At this early stage in the process, Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations or financial position.

On August 13, 2007, Midwest Generation and Commonwealth Edison received a letter signed by several Chicago-based environmental action groups stating that, in light of the NOV, the groups are examining the possibility of filing a citizen suit against Midwest Generation and Commonwealth Edison based presumably on the same or similar theories advanced by the US EPA in the NOV.

By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. Midwest Generation and Commonwealth Edison are cooperating with one another in responding to the NOV.

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. 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 December 31, 2007 and 2006, Homer City had a $1 million and a $17 million receivable recorded related to these claims, respectively, of which $3 million and $11 million were recorded during 2007 and 2006, respectively, related to business interruption insurance coverage and has been reflected in other income (expense), net in EME's consolidated income statements. EME Homer City received $18 million and $1 million in cash payments during 2007 and January 2008, respectively.

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. However, possible future developments, such as the promulgation of more stringent environmental laws and regulations, future proceedings that may be initiated by environmental and other regulatory authorities, cases in which new theories of liability are recognized, and settlements agreed to by other companies that establish precedent or expectations for the power industry, could affect the costs and the manner in which EME and its subsidiaries conduct their businesses and could require substantial additional capital or operational expenditures or the ceasing of operations at certain of their facilities. There is no assurance that EME's financial position and results of operations would not be materially adversely affected. EME is unable to predict the precise extent to which additional laws and regulations may affect its future operations and capital expenditure 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 or operational expenditures. If EME fails to comply with applicable environmental laws, it may be subject to injunctive relief or penalties and fines imposed by federal and state regulatory authorities.

Air Quality Regulation

The federal CAA, state clean air acts, and federal and state regulations implementing such statutes have substantial impacts on power generation facilities, particularly coal-fired plants. 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 SIPs will affect the costs and the manner in which EME conducts its business, and is expected to 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 Interstate Rule

The CAIR, issued by the US EPA on March 10, 2005, applies to 28 eastern states and the District of Columbia and is intended to address ozone and fine particulate matter attainment issues by reducing regional NO_X and SO_2 emissions. The CAIR reduces the current CAA Title IV Phase II SO_2 emissions allowance cap for 2010 and 2015 by 50% and 65%, respectively. The CAIR also requires reductions in regional NO_X emissions in 2009 and 2015 by 53% and 61%, respectively, from 2003 levels. The CAIR has been challenged in court by state, environmental and industry groups, 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, NO_X and SO_2 emissions at the Illinois Plants. The agreement has been embodied in rule language, called the CPS, and Midwest Generation's obligations under the agreement were conditioned upon the formal adoption of the CPS as a 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 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 with respect to the timing and amount of emissions reductions that 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 NO_X emissions from units to be determined by Midwest Generation in order to achieve an agreed-on fleetwide level of NO_X emissions per million Btu. Capital expenditures for these controls have been previously estimated (in 2006 dollars) to be approximately $450 million. See further discussion below regarding updating the estimated costs of completing environmental improvements.

During the third phase of the plan, the focus will be on the reduction of SO_2 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 the units 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 the third phase. Additional capital expenditures during the third phase of the plan have been previously estimated (in 2006 dollars) 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.

On May 30, 2006, the Illinois EPA submitted a proposed regulation to the Illinois Pollution Control Board (PCB) to implement the Illinois SIP required for compliance with the CAIR. The Illinois CAIR rule became final upon publication in the Illinois Register, which took place on September 7, 2007. Because the CPS involves mercury emissions, the US EPA has moved the CPS from the Illinois CAIR SIP to the Illinois CAMR SIP, which was pending final action by the US EPA prior to the February 8, 2008 U.S. Court of Appeals decision vacating the federal CAMR, discussed below. The US EPA approved the Illinois CAIR SIP (without the CPS included) effective as of December 17, 2007.

Pennsylvania—

On December 18, 2007, the Pennsylvania Environmental Quality Board approved the Pennsylvania CAIR. This rule has been submitted to the US EPA for approval as part of the Pennsylvania SIP. The Pennsylvania CAIR is substantively similar to the CAIR. EME Homer City will be subject to the federal CAIR rule during 2009 and expects to be able to comply with the NO_X requirement using its existing SCR system. The Pennsylvania CAIR, including both NO_X and SO_2 limits, is expected to become effective in 2010. EME Homer City expects to comply with Pennsylvania CAIR through the continued operation of its scrubber on Unit 3 to reduce SO_2 emissions and the purchase of SO_2 allowances.

Mercury Regulation

By means of a rule published in May 2005, the US EPA established the CAMR, which created the framework for a national, market-based cap-and-trade program to reduce mercury emissions from existing coal-fired power plants to a national cap of 38 tons by 2010 and to 15 tons by 2018, primarily through reductions in mercury achieved by lowering SO_2 and NO_X emissions under the CAIR. States were allowed, but not required, to join the trading program by adopting the CAMR model trading rules. States retained the right to promulgate alternative regulations equivalent to or more stringent than the CAMR cap-and-trade program, as long as the regulations were approved by the US EPA.

At the time that it published the CAMR, the US EPA also published a second rule, formally rescinding its previous finding that mercury emissions from electrical generating facilities had to be regulated as a hazardous air pollutant pursuant to Section 112 of the CAA, which would have imposed technology-based standards on emission sources. Both the CAMR and US EPA's decision to remove oil and coal-fired plants from the list of sources to be regulated under Section 112 of the CAA were challenged in the U.S. Court of Appeals for the D.C. Circuit by various environmental groups and state attorneys general.

On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated both rules and remanded the matter to the US EPA. As a result, until the US EPA takes further action in response to the remand, coal-fired electric generating facilities continue to be sources subject to regulation under Section 112 of the CAA and will be obligated to comply, on a case-by-case basis, with technology-based standards to control emissions of hazardous air pollutants (not necessarily limited to mercury) in accordance with the requirements of Section 112. As described below, EME's coal-fired electric generating facilities are already subject to significant unit-specific mercury emission reduction requirements under Illinois and Pennsylvania law. EME is assessing the potential impact of this decision on the Illinois and Pennsylvania regulations, including whether these regulations will turn out to be more or less stringent than case-by-case maximum achievable control technology (also known as MACT) standards or MACT standards that may eventually be promulgated by the US EPA.

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.

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. The Pennsylvania CAMR SIP, which embodies PADEP's mercury regulation, was pending approval by the US EPA prior to the February 8, 2008 Court of Appeals decision vacating the federal CAMR.

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 and coal washing on the other two units. In order to meet reductions in emissions by the 2015 deadline, it is likely that additional environmental control equipment will need to be installed. If additional environmental equipment is required in the form of flue gas desulfurization equipment, EME would need to make commitments during 2011 or 2012. EME continues to study available environmental control technologies and estimated costs to reduce SO_2 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.

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 as originally proposed 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.

On July 11, 2007 the US EPA issued a proposed rule to make revisions to the primary and secondary national ambient air quality standards for ozone. With regard to the primary standard for ozone, the US EPA proposes to reduce the level of the 8-hour standard to a level within the range of 0.070 to 0.075 parts per million (ppm). The US EPA solicited comment on alternative levels down to 0.060 ppm and up to and including retaining the current 8-hour standard of 0.08 ppm (effectively 0.084 ppm using current data rounding conventions). The rule may require states to impose further emission reductions beyond those necessary to meet the existing standards. EME anticipates that any such further emission 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 NO_X emission rate of 0.25 lb NO_X/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 "NO_X SIP Call" regulation that provided ozone-season NO_X emission allowances to a 19-state region east of the Mississippi. This program provides for NO_X allowance trading similar to the SO_2 (acid rain) trading program already in effect.

During 2004, the Illinois Plants stayed within their NO_X 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 NO_X allocations. In 2006 and 2007, the Illinois Plants used purchased allowances to stay within their NO_X 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 NO_X, SO_2, 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 in early 2008. The SIP for fine particulates is to be submitted to the US EPA by April 5, 2008.

The CPS requires Midwest Generation to install air pollution controls that will contribute to attainment with the ozone and fine particulate matter per National Ambient Air Quality Standards. Midwest Generation expects, but cannot guarantee, that the reductions required under the agreement and the CPS will be sufficient for compliance with future ozone and particulate matter regulations. See "—Clean Air Interstate Rule—Illinois" for further discussion.

Pennsylvania—

In June 2007, the PADEP requested a redesignation of Clearfield and Indiana counties to attainment with respect to the 8-hour ozone standard. The PADEP also submitted a maintenance plan indicating that the existing (and upcoming) regulations controlling emissions of volatile organic compounds and NO_x will result in continued compliance with the 8-hour ozone standard. Accordingly, EME believes that the Homer City facilities will likely not need to install additional pollution control as a result of the 8-hour ozone standard.

With respect to fine particulates, Pennsylvania has not proposed new regulations to achieve compliance with the National Ambient Air Quality Standard for fine particulates. The SIP with respect to this standard is due to the US EPA by April 5, 2008. Although the final form of the SIP is not yet known, at this time, EME does not anticipate that it will be required to install additional pollution controls at the Homer City facilities to meet the expected SIP requirements for fine particulates.

Regional Haze—

In July 1999, the US EPA published the "Regional Haze Rule" to reduce haze and protect visibility in designated federal areas. The goal of the 1999 rule is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions by 2064. 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. The US EPA issued a final rulemaking on regional haze on June 15, 2005. States were required to revise their SIPs by December 2007 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. 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 Interstate Rule—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 are being evaluated by the state.

New Source Review Requirements

Since 1999, the US EPA has pursued a coordinated compliance and enforcement strategy to address CAA NSR compliance issues at the nation's coal-fired power plants. The NSR regulations impose certain requirements on facilities, such as electric generating stations, if modifications are made to air emissions sources at a facility. The US EPA's strategy has included both the filing of suits against a number of power plant owners, and the issuance of administrative notices of violation to a number of 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 CAA 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 CAA 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 August 3, 2007, Midwest Generation received a NOV from the US EPA alleging that Midwest Generation and Commonwealth Edison violated various provisions of the NSR rules as well as state air regulations. See "—Commitments and Contingencies—Contingencies—Midwest Generation Potential Environmental Proceeding" for further discussion.

Water Quality Regulation

Regulations under the federal Clean Water Act require permits for the discharge of pollutants into United States waters and permits for the discharge of storm water flows from certain facilities. The Clean Water Act also regulates the thermal component (heat) of effluent discharges and the location, design, and construction of cooling water intake structures at generating facilities.

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 January 27, 2007, the Second Circuit rejected the US EPA rule and remanded it to the US EPA. Among the key provisions remanded by the court were the use of cost benefit and restoration to achieve compliance with the rule. On July 9, 2007, the US EPA suspended the requirements for cooling water intake structures, pending further rulemaking. The US EPA is expected to begin another rulemaking process by the end of 2008. 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—

On October 26, 2007, the Illinois EPA filed a proposed rule with the Illinois PCB that would establish more stringent thermal and effluent water quality standards for the Chicago Area Waterway System and Lower Des Plaines River. Midwest Generation's Fisk, Crawford, Joliet and Will County stations all use water from the affected waterways for cooling purposes and the rule, if implemented, is expected to affect the manner in which those stations use water for station cooling.

The proposed rule will be the subject of an administrative proceeding before the Illinois PCB and must be approved by the Illinois PCB and the Illinois Joint Committee on Administrative Rules. Following state adoption and approval, the US EPA also must approve the rule. Hearings began on January 28, 2008, and Midwest Generation is a party in those proceedings. At this time, it is not possible to predict the final form of the rule, how it would impact the operation of the affected stations, or the possible compliance costs or liability.

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 entered by the Pennsylvania state court on July 17, 2007. Under the consent order and agreement, EME Homer City paid a civil penalty of $200,000 and agreed to install modifications to its wastewater system to achieve consistent compliance with discharge limits. EME Homer City has operated the wastewater treatment system for twelve months without a selenium exceedance. At this time, EME expects to remain in compliance and consequently does not expect to install additional treatment systems.

Hazardous Substances and Hazardous Waste Laws

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. 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 $3 million at December 31, 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 investigation and/or remediation 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.

Climate Change

Federal Legislative Initiatives

To date, the United States has pursued a voluntary GHG emissions reduction program to meet its obligations as a signatory to the United Nations Framework Convention on Climate Change. As a result of increased attention to climate change in the U.S., however, numerous bills have been introduced in the current session of the U.S. Congress that would reduce GHG emissions in the U.S. Enactment of climate change legislation within the next several years may occur. However, there is still significant uncertainty about the cost of complying with any future GHG emission requirements. These costs will depend upon many factors, including the required levels of GHG emission reductions, the timing of those reductions, whether emission credits will be allocated with or without cost to existing generators, and whether flexible compliance mechanisms, such as a GHG offset program similar to those sanctioned under the CAA for conventional pollutants, will be part of the policy.

In most of the federal proposals to date, emission allowances would be allocated and distributed without cost in the early years of the emission reduction program, followed by decreasing free allocations and increasing auctions of allowances. While debate continues at the national level over domestic climate policy and the appropriate scope and terms of any federal legislation, many states are developing state-specific measures or participating in regional legislative initiatives to reduce GHG 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.

Regional Legislative Initiatives

On November 15, 2007, Illinois became a party to the Midwestern Accord, in which six of the thirteen states in the Midwestern Governors' Association including Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin and the Province of Manitoba, have agreed to seek to develop regional GHG emission reduction goals within one year, and to develop a multi-sector cap-and-trade program to achieve these goals. The accord called for such a program to be implemented in 30 months. On February 19, 2008, the six participating states announced that they will complete a model rule by the end of 2008 that will create the framework for the cap-and-trade program. Once this model rule has been drafted, each of the participating states could adopt the program through legislative action, executive order or other appropriate means. In February 2007, prior to the development of the Midwestern Accord, Illinois Governor Blagojevich announced a goal to reduce Illinois' GHG emissions to 1990 levels by 2020 and to 60% below 1990 levels by 2050.

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap-and-trade GHG 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.

In February 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington launched the Western Climate Initiative to develop regional strategies to address climate change. The Western Climate Initiative is identifying, evaluating and implementing collective and cooperative ways to reduce GHG in the region. In the spring of 2007, the Governor of Utah and the Premiers of British Columbia and Manitoba joined the Initiative. Other states and provinces have joined as observers. The Initiative partners set an overall regional goal in August 2007 for reducing GHG emissions to 15% below 2005 levels by 2020. By August 2008, these partners expect to complete the design of a market-based mechanism to help achieve that reduction goal.

Implementing regulations for such regional initiatives are likely to vary from state to state and may be more stringent and costly than federal legislative proposals currently being debated in Congress. It cannot yet be determined whether or to what extent any federal legislative system would preempt regional or state initiatives, although such preemption would greatly simplify compliance and eliminate regulatory duplication. If state and/or regional initiatives are allowed to stand together with federal legislation, generators could be required to purchase allowances to satisfy their state and federal compliance obligations.

State Specific Legislation

In September 2006, California's Governor Schwarzenegger has enacted two laws regarding GHG 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 GHG emissions. AB 32 requires the California Air Resources Board to develop regulations and market mechanisms targeted to reduce California's GHG emissions to 1990 levels by 2020. The California Air Resources Board's mandatory program will take effect commencing 2012 and will implement incremental reductions so that GHG emissions will be reduced to 1990 levels by 2020.

The second law, known as SB 1368, required the California Public Utilities Commission and the California Energy Commission to adopt GHG 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 August 29, 2007, the California Energy Commission adopted regulations pursuant to SB 1368 establishing and implementing GHG emissions performance standards for baseload generation of local publicly owned electric utilities. Utility purchases of power generated by EME's facilities in California are subject to the emissions performance standards established in SB 1368.

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 GHG 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.

Litigation Developments

The speed with which federal regulations and legislation will be adopted will depend in part on decisions rendered in climate change litigation pending before several federal and state courts and the US EPA's response to those decisions. For example, on April 2, 2007, the United States Supreme Court issued an opinion in *Massachusetts et al. v. Environmental Protection Agency, et. al.*, ruling that the US EPA has the authority to regulate GHG emissions of new motor vehicles under the CAA and that it has a duty to (i) determine whether GHG 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 the 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 CAA related to emissions of motor vehicles, a parallel provision of the CAA applies to stationary sources such as electric generators, and there is litigation pending in the D.C. Circuit Court of Appeals, *Coke Oven Task Force v. Environmental Protection Agency*, in which the holding in *Massachusetts v. Environmental Protection Agency, et al.,* may be applied to stationary sources such as power plants.

On December 19, 2007, the Administrator of the US EPA announced that the US EPA would not grant the waiver that California had been seeking under established CAA procedures to implement stringent GHG emission reduction requirements for motor vehicles. At least 16 other states have adopted or announced plans to adopt California's regulations. On January 2, 2008, California sued the US EPA in the 9th Circuit U.S. Court of Appeals challenging the decision to deny California's request for a waiver. While these developments apply only to automotive sources of GHG emissions, they reflect heightened regulatory scrutiny of, and public concern about, GHG emissions across all sectors of the economy, including power generation.

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 another case brought in April 2006, private citizens filed a complaint in the 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. In August 2007, the court dismissed the case entirely. The plaintiffs have appealed this dismissal in the Fifth Circuit Court of Appeals.

On October 18, 2007, the Kansas Department of Health and Environment rejected a permit to construct two proposed coal-fired electrical generators based on the impact to health and the environment arising from the proposed units' emissions of carbon dioxide. This was the first reported rejection of a proposed coal plant permit based on a clean air statute. This decision has been appealed. In addition, there are a number of pending cases in which environmental groups are arguing that air permits for the construction of major coal-fired generating facilities cannot be issued unless the permits include best available control technology to control carbon dioxide emissions. The US EPA has taken the position that such controls are not required until it finalizes regulations relating to carbon dioxide emissions.

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 that would impose additional costs or charges for the emission of carbon dioxide could have a materially adverse effect on EME. EME will continue to monitor the federal, regional and state developments relating to regulation of GHG emissions to determine their impact on its operations. Requirements to reduce emissions of carbon dioxide and other GHG emissions could significantly increase the cost of generating electricity from fossil fuels, especially coal, as well as the cost of purchased power.

Note 13. Related Party Transactions

Specified administrative services such as payroll and employee benefit programs, all performed by Edison International or SCE employees, are shared among all affiliates of Edison International, and the costs of these corporate support services are allocated to all affiliates, including EME. Costs are allocated based on one of the following formulas: percentage of time worked, equity in investment and advances, number of employees, or multi-factor (operating revenues, operating expenses, total assets and number of employees). In addition, services of Edison International or SCE employees are sometimes directly requested by EME and these services are performed for EME's benefit. Labor and expenses of these directly requested services are specifically identified and billed at cost. EME believes the allocation methodologies utilized are reasonable. EME made reimbursements for the cost of these programs and other services, which amounted to $76 million, $69 million and $84 million in 2007, 2006 and 2005, respectively. At December 31, 2007 and 2006, the amount due to Edison International was $3 million and $4 million, respectively.

EME participates in the insurance program of Edison International, including property, general liability, workers compensation and various other specialty policies. EME's insurance premiums are generally based on EME's share of risk related to each policy. In connection with the property insurance program, a portion of the risk is reinsured by a captive insurance subsidiary of Edison International.

EME records accruals for tax liabilities and/or tax benefits which are settled quarterly according to a series of tax-allocation agreements as described in Note 1. Under these agreements, EME recognized tax liabilities applicable to continuing operations of $152 million, $81 million and $270 million for 2007, 2006 and 2005, respectively. See Note 10—Income Taxes. At December 31, 2007 and 2006, amounts included in payables to affiliates associated with the tax liabilities totaled $1 million and $(1) million, respectively.

Edison Mission Operation & Maintenance, Inc., an indirect, wholly owned affiliate of EME, has entered into operation and maintenance agreements with partnerships in which EME has a 50% or less ownership interest. Pursuant to the negotiated agreements, Edison Mission Operation & Maintenance is to perform all operation and maintenance activities necessary for the production of power by these partnerships' facilities. The agreements continue until terminated by either party. Edison Mission Operation & Maintenance is paid for all costs incurred with operating and maintaining such facilities and may also earn incentive compensation as set forth in the agreements. EME recorded revenues under the operation and maintenance agreements of $30 million for 2007, $26 million for 2006 and $24 million for 2005. Receivables from affiliates for Edison Mission Operation & Maintenance totaled $11 million and $7 million at December 31, 2007 and 2006, respectively.

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 $747 million, $756 million and $932 million in 2007, 2006 and 2005, respectively.

Note 14. Supplemental Statements of Cash Flows Information

	Years Ended December 31,		
	2007	2006	2005
		(in millions)	
Cash paid			
Interest (net of amount capitalized)	$320	$297	$309
Income taxes	120	172	149
Cash payments under plant operating leases	336	337	293
Details of assets acquired			
Fair value of assets acquired	$ 41	$ 29	$154
Liabilities assumed	—	—	—
Net assets acquired	$ 41	$ 29	$154
Non-cash activities from consolidation of variable interest entities			
Assets	$ 12	$ 18	$ 37
Liabilities	5	4	27

In connection with certain wind projects acquired during the years ended December 31, 2007 and 2006, the purchase price included payments that were due upon the start and completion of construction. Accordingly, EME accrued for estimated payments related to wind projects primarily due upon completion of construction scheduled during 2008 and made payments primarily related to wind projects completed during 2007.

During the year ended December 31, 2006, EME received a capital contribution of $76 million in the form of ownership interests in a portfolio of wind projects and a small biomass project. Refer to Note 4—Acquisitions and Consolidations—Transfer of Wind Projects from an Affiliate, for further discussion.

During the year ended December 31, 2005, EME received a capital contribution of $20 million from its parent for investments in an entity which was previously owned by EME's affiliate, Edison Capital. This entity holds interests in various wind projects.

Note 15. Quarterly Financial Data (unaudited)

2007	First	Second	Third(i)	Fourth	Total
			(in millions)		
Operating revenues	$ 673	$ 570	$ 712	$ 625	$ 2,580
Operating income	247	107	261	149	764
Income (loss) from continuing operations	153	(19)(ii)	194	88	416
Discontinued operations, net	3	2	(4)	(3)	(2)
Income (loss) before accounting change	156	(17)	190	85	414
Net income (loss)	156	(17)	190	85	414

2006	First	Second	Third(i)	Fourth	Total
			(in millions)		
Operating revenues	$ 514	$ 463	$ 706	$ 556	$ 2,239
Operating income	135	54	287	147	623
Income (loss) from continuing operations	75	(43)(iii)	198	86	316
Discontinued operations, net(iv)	73	4	(2)	23	98
Income (loss) before accounting change	148	(39)	196	109	414
Net income (loss)	148	(39)	196	109	414

(i) Reflects EME's seasonal pattern, in which a significant amount of earnings from domestic projects are earned and recorded in the third quarter of each year.

(ii) Reflects a $160 million pre-tax ($98 million, after tax) loss on early extinguishment of debt 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.

(iii) Reflects a $143 million pre-tax ($88 million, after tax) loss on early extinguishment of debt related to the early repayment of substantially all of EME's 10% senior notes due August 15, 2008 and 9.875% senior notes due April 15, 2011.

(iv) See Note 5—Divestitures—Discontinued Operations, for more information.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Omitted pursuant to General Instruction I.(2)(c).

Code of Business Conduct and Ethics for Principal Officers

The Edison International Ethics and Compliance Code is applicable to all directors, officers and employees of Edison International and its majority-owned subsidiaries, including EME. The Code is available on the Internet website maintained by EME's ultimate parent, Edison International, at www.edisonethics.com and is available in print without charge upon request from Edison International's Corporate Secretary. Any amendments or waivers of Code provisions for EME's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, will be posted on Edison International's Internet website at www.edisonethics.com.

ITEM 11. EXECUTIVE COMPENSATION

Omitted pursuant to General Instruction I.(2)(c).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Omitted pursuant to General Instruction I.(2)(c).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Omitted pursuant to General Instruction I.(2)(c).

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

INDEPENDENT ACCOUNTANT FEES

The following table sets forth the aggregate fees billed to EME (consolidated total including EME and its subsidiaries), for the fiscal years ended December 31, 2007 and December 31, 2006, by PricewaterhouseCoopers LLP:

	EME and Subsidiaries ($000)	
	2007	**2006**
Audit Fees	$ 2,365	$ 2,678
Audit Related Fees(1)	172	193
Tax Fees(2)	922	1,151
All Other Fees	—	—
Total	$ 3,459	$ 4,022

(1) The nature of the services comprising these fees were assurance and related services related to the performance of the audit or review of the financial statements and not reported under "Audit Fees" above.

(2) The nature of the services comprising these fees were to support compliance with federal, state and foreign tax reporting and payment requirements, including tax return review and review of tax laws, regulations or cases.

The Edison International Audit Committee reviews with management and pre-approves all audit services to be performed by the independent accountants and all non-audit services that are not prohibited and that require pre-approval under the Securities Exchange Act. The Edison International Audit Committee's pre-approval responsibilities may be delegated to one or more Edison International Audit Committee members, provided that such delegate(s) presents any pre-approval decisions to the Edison International Audit Committee at its next meeting. The Committee has delegated such pre-approval responsibilities to the Committee Chair. The independent auditors must assure that all audit and non-audit services provided to EME and its subsidiaries have been approved by the Edison International Audit Committee.

During the fiscal year ended December 31, 2007, all services performed by the independent accountants were pre-approved by the Edison International Audit Committee, regardless of whether the services required pre-approval under the Securities Exchange Act.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) List of Financial Statements

See Index to Consolidated Financial Statements at Item 8 of this report.

(2) List of Financial Statement Schedules

The following financial statement schedule is included in this report:

	Page
Schedule I—Condensed Financial Information of Parent	179

All other schedules have been omitted because they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

(3) List of Exhibits

Exhibit No.	Description
2.1	Asset Purchase Agreement, dated August 1, 1998, between Pennsylvania Electric Company, NGE Generation, Inc., New York State Electric & Gas Corporation and Mission Energy Westside, Inc., incorporated by reference to Exhibit 2.4 to Edison Mission Energy's Form 10-K for the year ended December 31, 1998.
2.2	Asset Sale Agreement, dated March 22, 1999, between Commonwealth Edison Company and Edison Mission Energy as to the Fossil Generating Assets, incorporated by reference to Exhibit 2.5 to Edison Mission Energy's Form 10-K for the year ended December 31, 1998.
2.3	Purchase and Sale Agreement, dated May 10, 2000, between Edison Mission Energy, P & L Coal Holdings Corporation and Gold Fields Mining Corporation, incorporated by reference to Exhibit 2.9 to Edison Mission Energy's 10-Q for the quarter ended September 30, 2000.
2.4	Stock Purchase Agreement, dated November 17, 2000 between Mission Del Sol, LLC and Texaco Inc., incorporated by reference to Exhibit 2.11 to Edison Mission Energy's Form 10-K for the year ended December 31, 2000.
2.5	Purchase Agreement, dated July 20, 2004, between Edison Mission Energy and Origin Energy New Zealand Limited, incorporated by reference to Exhibit 2.1 to Edison Mission Energy's Form 8-K filed October 4, 2004.
2.6	Purchase Agreement, dated July 29, 2004, by and among Edison Mission Energy, IPM Eagle LLP, International Power plc, Mitsui & Co., Ltd. and the other sellers on the signature page thereto, incorporated by reference to Exhibit 2.1 to Edison Mission Energy's Form 10-Q for the quarter ended September 30, 2004.
3.1	Certificate of Incorporation of Edison Mission Energy, dated August 14, 2001, incorporated by reference to Exhibit 3.1 to Edison Mission Energy's Form 8-K filed October 29, 2001.
3.1.1	Certificate of Amendment to the Certificate of Incorporation of Edison Mission Energy, dated May 4, 2004, incorporated by reference to Exhibit 3.1.1 to Edison Mission Energy's Form 10-Q for the quarter ended March 31, 2004.
3.1.2	Certificate of Amendment to the Certificate of Incorporation of Edison Mission Energy, dated August 8, 2007, incorporated by reference to Exhibit 3.1.2 to Edison Mission Energy's Form 10-Q for the quarter ended June 30, 2007.

Exhibit No.	Description
3.2	By-Laws of Edison Mission Energy, dated May 4, 2004, incorporated by reference to Exhibit 3.1.1 to Edison Mission Energy's Form 10-Q for the quarter ended March 31, 2004.
4.1	Indenture, dated as of May 7, 2007, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, incorporated by reference to Exhibit 4.1 to Edison Mission Energy's Form 8-K filed May 10, 2007.
4.1.1	First Supplemental Indenture, dated as of May 7, 2007, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of May 7, 2007, incorporated by reference to Exhibit 4.1.1 to Edison Mission Energy's Form 8-K filed May 10, 2007.
4.1.2	Second Supplemental Indenture, dated as of May 7, 2007, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of May 7, 2007, incorporated by reference to Exhibit 4.1.2 to Edison Mission Energy's Form 8-K filed May 10, 2007.
4.1.3	Third Supplemental Indenture, dated as of May 7, 2007, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of May 7, 2007, incorporated by reference to Exhibit 4.1.3 to Edison Mission Energy's Form 8-K filed May 10, 2007.
4.1.4	Fourth Supplemental Indenture, dated as of August 22, 2007, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of May 7, 2007, incorporated by reference to Exhibit 4.1.4 to Edison Mission Energy's Form S-4 filed September 10, 2007.
4.2	Second Supplemental Indenture, dated as of April 30, 2007, between Edison Mission Energy and The Bank of New York, as trustee, supplementing the Indenture, dated as of June 28, 1999, pursuant to which Edison Mission Energy's 7.73% Senior Notes due 2009 were issued, incorporated by reference to Exhibit 4.1 to Edison Mission Energy's Form 8-K filed May 1, 2007.
4.3	Indenture, dated as of June 6, 2006, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, incorporated by reference to Exhibit 4.1 to Edison Mission Energy's Form 8-K filed June 8, 2006.
4.3.1	First Supplemental Indenture, dated as of June 6, 2006, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of June 6, 2006, incorporated by reference to Exhibit 4.1.1 to Edison Mission Energy's Form 8-K filed June 8, 2006.
4.3.2	Second Supplemental Indenture, dated as of June 6, 2006, between Edison Mission Energy and Wells Fargo Bank, National Association, as trustee, supplementing the Indenture, dated as of June 6, 2006, incorporated by reference to Exhibit 4.1.2 to Edison Mission Energy's Form 8-K filed June 8, 2006.
4.4	Guarantee, dated as of August 17, 2000, made by Edison Mission Energy, as Guarantor in favor of Powerton Trust I, as Owner Lessor, incorporated by reference to Exhibit 4.9 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.4.1	Schedule identifying substantially identical agreement to Guarantee constituting Exhibit 4.4 hereto, incorporated by reference to Exhibit 4.9.1 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.

Exhibit No.	Description
4.5	Guarantee, dated as of August 17, 2000, made by Edison Mission Energy, as Guarantor in favor of Joliet Trust I, as Owner Lessor, incorporated by reference to Exhibit 4.10 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.5.1	Schedule identifying substantially identical agreement to Guarantee constituting Exhibit 4.5 hereto, incorporated by reference to Exhibit 4.10.1 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.6	Participation Agreement (T1), dated as of August 17, 2000, by and among, Midwest Generation, LLC, Powerton Trust I, as the Owner Lessor, Wilmington Trust Company, as the Owner Trustee, Powerton Generation I, LLC, as the Owner Participant, Edison Mission Energy, United States Trust Company of New York, as the Lease Indenture Trustee, and United States Trust Company of New York, as the Pass Through Trustees, incorporated by reference to Exhibit 4.12 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.6.1	Schedule identifying substantially identical agreement to Participation Agreement constituting Exhibit 4.6 hereto, incorporated by reference to Exhibit 4.12.1 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.7	Participation Agreement (T1), dated as of August 17, 2000, by and among, Midwest Generation, LLC, Joliet Trust I, as the Owner Lessor, Wilmington Trust Company, as the Owner Trustee, Joliet Generation I, LLC, as the Owner Participant, Edison Mission Energy, United States Trust Company of New York, as the Lease Indenture Trustee and United States Trust Company of New York, as the Pass Through Trustees, incorporated by reference to Exhibit 4.13 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.7.1	Schedule identifying substantially identical agreement to Participation Agreement constituting Exhibit 4.7 hereto, incorporated by reference to Exhibit 4.13.1 to Edison Mission Energy's and Midwest Generation LLC's Registration Statement on Form S-4 to the Securities and Exchange Commission on April 20, 2001.
4.8	Indenture, dated as of June 28, 1999, between Edison Mission Energy and The Bank of New York, as Trustee, incorporated by reference to Exhibit 4.1 to Edison Mission Energy's Registration Statement on Form S-4 to the Securities and Exchange Commission on February 18, 2000.
4.8.1	First Supplemental Indenture, dated as of June 28, 1999, to Indenture dated as of June 28, 1999, between Edison Mission Energy and The Bank of New York, as Trustee, incorporated by reference to Exhibit 4.2 to Edison Mission Energy's Registration Statement on Form S-4 to the Securities and Exchange Commission on February 18, 2000.
4.9	Promissory Note ($499,450,800), dated as of August 24, 2000, by Edison Mission Energy in favor of Midwest Generation, LLC, incorporated by reference to Exhibit 4.5 to Edison Mission Energy's Form 10-K for the year ended December 31, 2000.
4.9.1	Schedule identifying substantially identical agreements to Promissory Note constituting Exhibit 4.9 hereto, incorporated by reference to Exhibit 4.5.1 to Edison Mission Energy's Form 10-K for the year ended December 31, 2000.

Exhibit No.	Description
4.10	Participation Agreement, dated as of December 7, 2001, among EME Homer City Generation L.P., Homer City OL1 LLC, as Facility Lessor and Ground Lessee, Wells Fargo Bank Northwest National Association, General Electric Capital Corporation, The Bank of New York as the Security Agent, The Bank of New York as Lease Indenture Trustee, Homer City Funding LLC and The Bank of New York as Bondholder Trustee, incorporated by reference to Exhibit 4.4 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.
4.10.1	Schedule identifying substantially identical agreements to Participation Agreement constituting Exhibit 4.10 hereto, incorporated by reference to Exhibit 4.4.1 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.
4.10.2	Appendix A (Definitions) to the Participation Agreement constituting Exhibit 4.10 hereto, incorporated by reference to Exhibit 4.4.2 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2004.
4.11	Open-End Mortgage, Security Agreement and Assignment of Rents, dated as of December 7, 2001, among Homer City OLI LLC, as the Owner Lessor to The Bank of New York, as Security Agent and Mortgagee, incorporated by reference to Exhibit 4.9 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.
4.11.1	Schedule identifying substantially identical agreements to Open-End Mortgage, Security Agreement and Assignment of Rents constituting Exhibit 4.11 hereto, incorporated by reference to Exhibit 4.9.1 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2003.
10.1†	Purchase & Reservation Agreement, dated as of June 4, 2007, between Edison Mission Energy and Suzlon Wind Energy Corporation, incorporated by reference to Exhibit 10.1 to Edison Mission Energy's Form 10-Q for the quarter ended June 30, 2007.
10.2†	Supply Agreement, dated as of March 28, 2007, between Edison Mission Energy and Mitsubishi Power Systems Americas, Inc., incorporated by reference to Exhibit 10.1 to Edison Mission Energy's Form 10-Q for the quarter ended March 31, 2007.
10.3	Credit Agreement, dated as of June 15, 2006, between Edison Mission Energy, the Lenders referred to therein, the Issuing Lenders referred to therein and Citicorp North America, Inc., as Administrative Agent for the Lenders and the Issuing Lenders party thereto, incorporated by reference to Exhibit 10.1 to Edison Mission Energy's Form 8-K filed June 21, 2006.
10.3.1	Amendment No. 1 to Credit Agreement (amending the Credit Agreement listed as Exhibit 10.3 herein), dated as of May 7, 2007, among Edison Mission Energy, the Lenders party thereto, the Issuing Lenders party thereto, and Citigroup North America Inc., as administrative agent, incorporated by reference to Exhibit 10.1 to Edison Mission Energy's Form 8-K filed May 10, 2007.
10.4	Credit Agreement, dated as of April 27, 2004 among Midwest Generation, LLC, the Lenders referred to therein, the Issuing Lenders referred to therein and Citicorp North America, Inc., as Administrative Agent for the Lenders and the Issuing Lenders party thereto, incorporated by reference to Exhibit 4.3 to Midwest Generation, LLC's Form 10-Q for the quarter ended March 31, 2004.

Exhibit No.	Description
10.4.1	First Amended and Restated Credit Agreement (amending and restating the Credit Agreement listed as Exhibit 10.4 herein), dated as of April 18, 2005 among Midwest Generation, LLC, the Lenders referred to therein the Citicorp North America, Inc., as Administrative Agent for the Lenders and the Issuing Lenders thereto, incorporated by reference to Exhibit 10.1 to Midwest Generation, LLC's Form 10-Q for the quarter ended March 31, 2005.
10.4.2	Second Amended and Restated Credit Agreement (amending and restating the Credit Agreement listed as Exhibit 10.4 herein), dated as of December 15, 2005, among Midwest Generation, LLC, the Lenders referred to therein and Citicorp North America, Inc. as Administrative Agent for the Lenders and the Issuing Lenders party thereto, incorporated by reference to Exhibit 10.6.2 to Midwest Generation, LLC's Form 10-K for the year ended December 31, 2005.
10.4.3	Third Amended and Restated Credit Agreement (amending and restating the Credit Agreement listed as Exhibit 10.4 herein), dated June 29, 2007, among Midwest Generation, LLC and the Lenders referred to therein and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders and the Issuing Lenders party thereto, incorporated by reference to Exhibit 10.1 to Midwest Generation, LLC's Form 10-Q for the quarter ended June 30, 2007.
10.5	Security Agreement, dated as of June 15, 2006, between Edison Mission Energy and Citicorp North America, Inc., as Administrative Agent, incorporated by reference to Exhibit 10.2 to Edison Mission Energy's Form 8-K filed June 21, 2006.
10.6	Guarantee, dated August 1, 1998, between Edison Mission Energy, Pennsylvania Electric Company, NGE Generation, Inc. and New York State Electric & Gas Corporation, incorporated by reference to Exhibit 10.54 to Edison Mission Energy's Form 10-K for the year ended December 31, 1998.
10.7	Amended and Restated Guarantee and Collateral Agreement, dated as of December 7, 2001, made by EME Homer City Generation L.P. in favor of The Bank of New York as successor to United States Trust Company of New York, as Collateral Agent, incorporated by reference to Exhibit 10.16.4 to EME Homer City Generation L.P.'s Form 10-K for the year ended December 31, 2001.
10.8	Amended and Restated Security Deposit Agreement, dated as of December 7, 2001, among EME Homer City Generation L.P. and The Bank of New York as Collateral Agent, incorporated by reference to Exhibit 10.18.2 to the EME Homer City Generation L.P. Form 10-K for the year ended December 31, 2001.
10.9	Intercompany Loan Subordination Agreement, dated March 18, 1999, among Edison Mission Holdings Co., Edison Mission Finance Co., Homer City Property Holdings, Inc., Chestnut Ridge Energy Co., Mission Energy Westside, Inc., EME Homer City Generation L.P. and United States Trust Company of New York, incorporated by reference to Exhibit 10.60.3 to Amendment No. 2 of Edison Mission Holdings Co.'s Registration Statement on Form S-4 to the Securities and Exchange Commission on February 29, 2000.
10.10	Reimbursement Agreement, dated as of October 26, 2001, between Edison Mission Energy and Midwest Generation, LLC, incorporated by reference to Exhibit 10.15 to Edison Mission Energy's Form 10-Q for the quarter ended March 31, 2004.
10.11	Tax Allocation Agreement, dated July 2, 2001, by and between Mission Energy Holding Company and Edison Mission Energy, incorporated by reference to Exhibit 10.106 to Edison Mission Energy's Form 10-Q for the quarter ended September 30, 2002.

Exhibit No.	Description
10.12	Administrative Agreement Re Tax Allocation Payments, dated July 2, 2002, among Edison International and subsidiary parties, incorporated by reference to Exhibit 10.107 to Edison Mission Energy's Form 10-Q for the quarter ended September 30, 2002.
31.1*	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
31.2*	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
32*	Statement Pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

† Confidential treatment granted.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EDISON MISSION ENERGY
(REGISTRANT)

By: /s/ W. James Scilacci

W. James Scilacci
Senior Vice President and Chief Financial Officer

Date: June 17, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Ronald L. Litzinger Ronald L. Litzinger	Director, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	June 17, 2008
/s/ W. James Scilacci W. James Scilacci	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	June 17, 2008
/s/ Mark C. Clarke Mark C. Clarke	Vice President and Controller (Controller or Principal Accounting Officer)	June 17, 2008
/s/ Thomas R. McDaniel Thomas R. McDaniel	Director	June 17, 2008
/s/ Jacob A. Bouknight, Jr. Jacob A. Bouknight, Jr.	Director	June 17, 2008

SCHEDULE I

EDISON MISSION ENERGY AND SUBSIDIARIES
CONDENSED FINANCIAL INFORMATION OF PARENT
Condensed Balance Sheets
(In millions)

	December 31, 2007	December 31, 2006
Assets		
Cash and cash equivalents	$ 664	$ 813
Short-term investments	81	558
Affiliate receivables	16	6
Other current assets	32	49
Total current assets	793	1,426
Investments in subsidiaries	6,404	4,766
Other long-term assets	512	233
Total Assets	$ 7,709	$ 6,425
Liabilities and Shareholder's Equity		
Accounts payable and accrued liabilities	$ 94	$ 62
Affiliate payables	517	648
Current maturities of long-term debt	—	78
Total current liabilities	611	788
Long-term obligations	3,713	1,599
Long-term affiliate debt	1,356	1,359
Deferred taxes and other	106	97
Total Liabilities	5,786	3,843
Common Shareholder's Equity	1,923	2,582
Total Liabilities and Shareholder's Equity	$ 7,709	$ 6,425

SCHEDULE I

EDISON MISSION ENERGY AND SUBSIDIARIES
CONDENSED FINANCIAL INFORMATION OF PARENT
Condensed Statements of Income
(In millions)

	Years Ended December 31,		
	2007	2006	2005
Operating revenues	$ 7	$ 5	$ —
Operating expenses	(121)	(81)	(110)
Operating loss	(114)	(76)	(110)
Equity in income from continuing operations of subsidiaries	1,069	638	680
Interest expense and other	(356)	(346)	(270)
Income before income taxes	599	216	300
Provision (benefit) for income taxes	185	(198)	(142)
Net income	$ 414	$ 414	$ 442

SCHEDULE I

EDISON MISSION ENERGY AND SUBSIDIARIES
CONDENSED FINANCIAL INFORMATION OF PARENT
Condensed Statements of Cash Flows
(In millions)

	Years Ended December 31,		
	2007	2006	2005
Net cash provided by (used in) operating activities	$ 327	$ 942	$ (2,594)
Net cash used in financing activities	(525)	(415)	(378)
Net cash provided by (used in) investing activities	49	(514)	1,796
Net increase (decrease) in cash and cash equivalents	(149)	13	(1,176)
Cash and cash equivalents at beginning of period	813	800	1,976
Cash and cash equivalents at end of period	$ 664	$ 813	$ 800
Cash dividends received from subsidiaries	$ 660	$ 543	$ 250