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

Form 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended September 30, 2006

or

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

For the transition period from ______________ to ______________

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**

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 whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

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

Number of shares outstanding of the registrant's Common Stock as of November 3, 2006: 100 shares (all shares held by an affiliate of the registrant).

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PART I—FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Operating Revenues				
Electric revenues	$ 621	$ 643	$ 1,535	$ 1,541
Net gains from price risk management and energy trading	76	31	117	60
Operation and maintenance services	6	6	19	18
Other revenues	3	—	12	—
Total operating revenues	706	680	1,683	1,619
Operating Expenses				
Fuel	200	193	491	492
Plant operations	99	97	365	351
Plant operating leases	44	45	132	133
Operation and maintenance services	5	5	18	17
Depreciation and amortization	36	33	107	99
Asset impairment charges	—	—	—	7
Administrative and general	36	30	100	100
Total operating expenses	420	403	1,213	1,199
Operating income	286	277	470	420
Other Income (Expense)				
Equity in income from unconsolidated affiliates	89	114	160	197
Impairment loss on equity method investment	—	(55)	—	(55)
Interest income	25	15	68	42
Other income (expense), net	1	—	20	(3)
Gain on sale of assets	—	—	4	—
Loss on early extinguishment of debt	—	—	(143)	(4)
Interest expense	(69)	(74)	(214)	(225)
Total other income (expense)	46	—	(105)	(48)
Income from continuing operations before income taxes	332	277	365	372
Provision for income taxes	134	104	135	123
Income From Continuing Operations	198	173	230	249
Income (loss) from operations of discontinued subsidiaries, net of tax (Note 7)	(2)	27	75	55
Net Income	$ 196	$ 200	$ 305	$ 304

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Net Income	$ 196	$ 200	$ 305	$ 304
Other comprehensive income (loss), net of tax:				
Minimum pension liability adjustment, net of income tax effect	—	—	(2)	—
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 $67 and $(122) for the three months and $239 and $(165) for the nine months ended September 30, 2006 and 2005, respectively	94	(167)	347	(221)
Reclassification adjustments included in net income, net of income tax expense of $8 and $51 for the three months and $16 and $56 for the nine months ended September 30, 2006 and 2005, respectively	(11)	(72)	(23)	(80)
Other comprehensive income (loss)	83	(239)	322	(301)
Comprehensive Income (Loss)	$ 279	$ (39)	$ 627	$ 3

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

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

	September 30, 2006	December 31, 2005
Assets		
Current Assets		
Cash and cash equivalents	$ 1,564	$ 1,155
Short-term investments	366	183
Accounts receivable—trade	188	337
Accounts receivable—affiliates	8	18
Inventory	169	120
Assets under price risk management and energy trading	224	78
Margin and collateral deposits	169	561
Deferred taxes	—	155
Prepaid expenses and other	58	68
Total current assets	2,746	2,675
Investments in Unconsolidated Affiliates	411	405
Property, Plant and Equipment	4,063	3,856
Less accumulated depreciation and amortization	947	844
Net property, plant and equipment	3,116	3,012
Other Assets		
Deferred financing costs	47	43
Long-term assets under price risk management and energy trading	176	90
Restricted cash	116	105
Rent payments in excess of levelized rent expense under plant operating leases	555	395
Long-term margin and collateral deposits	29	137
Other long-term assets	92	161
Total other assets	1,015	931
Total Assets	$ 7,288	$ 7,023

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

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

	September 30, 2006	December 31, 2005
Liabilities and Shareholder's Equity		
Current Liabilities		
Accounts payable—affiliates	$ 90	$ 32
Accounts payable	57	64
Accrued liabilities	190	207
Liabilities under price risk management and energy trading	115	418
Interest payable	82	51
Deferred taxes	16	—
Current maturities of long-term obligations	132	74
Total current liabilities	682	846
Long-term obligations net of current maturities	3,102	3,330
Deferred taxes and tax credits	369	227
Long-term liabilities under price risk management and energy trading	15	83
Other long-term liabilities	594	598
Total Liabilities	4,762	5,084
Minority Interest	43	29
Commitments and Contingencies (Note 10)		
Shareholder's Equity		
Common stock, par value $0.01 per share; 10,000 shares authorized; 100 shares issued and outstanding as of September 30, 2006 and December 31, 2005	64	64
Additional paid-in capital	2,174	2,228
Retained earnings (accumulated deficit)	134	(171)
Accumulated other comprehensive income (loss)	111	(211)
Total Shareholder's Equity	2,483	1,910
Total Liabilities and Shareholder's Equity	$ 7,288	$ 7,023

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

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

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005 Revised(1)
Cash Flows From Operating Activities		
Net income	$ 305	$ 304
Less: Income from discontinued operations	(75)	(55)
Income from continuing operations, net	$ 230	$ 249
Adjustments to reconcile income to net cash used in operating activities:		
Equity in income from unconsolidated affiliates	(160)	(197)
Distributions from unconsolidated affiliates	132	153
Depreciation and amortization	114	104
Deferred taxes and tax credits	88	137
Gain on sale of assets	(4)	—
Loss on early extinguishment of debt	143	4
Impairment charges	—	62
Changes in operating assets and liabilities:		
Decrease (increase) in margin and collateral deposits	500	(684)
Decrease (increase) in accounts receivable	159	(163)
Increase in inventory	(49)	(11)
Decrease in prepaid expenses and other	15	63
Increase in rent payments in excess of levelized rent expense	(160)	(115)
Increase in accounts payable and accrued liabilities	63	61
Increase in interest payable	31	34
Increase (decrease) in net assets under risk management	(31)	32
Other operating—assets	(2)	6
Other operating—liabilities	(39)	(13)
	1,030	(278)
Operating cash flow from discontinued operations	82	20
Net cash provided by (used in) operating activities	1,112	(258)
Cash Flows From Financing Activities		
Borrowings on long-term debt	1,395	168
Payments on long-term debt agreements	(1,563)	(545)
Cash distribution to parent	—	(6)
Cash dividends to parent	(51)	(360)
Payments to affiliates related to stock-based awards	(23)	(13)
Excess tax benefits related to stock option exercises	5	—
Premium paid on extinguishment of debt and financing costs	(153)	(5)
Net cash used in financing activities	(390)	(761)
Cash Flows From Investing Activities		
Capital expenditures	(142)	(42)
Proceeds from return of capital	12	—
Purchase of interest of acquired companies	(18)	—
Proceeds from sale of interest in projects	43	—
Proceeds from sale of discontinued operations	—	124
Purchase of short-term investments	(305)	—
Maturities and sales of short-term investments	121	140
(Increase) decrease in restricted cash	(7)	77
Turbine deposits	(54)	—
Proceeds from other assets	37	—
	(313)	299
Investing cash flow from discontinued operations	—	5
Net cash provided by (used in) investing activities	(313)	304
Effect of consolidation of variable interest entities on cash	—	3
Net increase (decrease) in cash and cash equivalents	409	(712)
Cash and cash equivalents at beginning of period	1,155	2,274
Cash and cash equivalents at end of period	1,564	1,562
Cash and cash equivalents classified as part of discontinued operations	—	(1)
Cash and cash equivalents of continuing operations	$ 1,564	$ 1,561

(1) See Note 1—Revisions for further explanation.

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

Note 1. General

In the opinion of management, all adjustments, including recurring accruals, have been made that are necessary to fairly state the consolidated financial position and results of operations and cash flows for the periods covered by this quarterly report on Form 10-Q. The results of operations for the nine months ended September 30, 2006 are not necessarily indicative of the operating results for the full year.

Edison Mission Energy's (EME's) significant accounting policies are described in Note 2 to its Consolidated Financial Statements as of December 31, 2005 and 2004, included in EME's annual report on Form 10-K for the year ended December 31, 2005. EME follows the same accounting policies for interim reporting purposes, with the exception of the change in accounting for stock-based compensation (explained below) and production tax credits explained in Note 9—Income Taxes. This quarterly report should be read in connection with such financial statements. Terms used but not defined in this report are defined in EME's annual report on Form 10-K for the year ended December 31, 2005.

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. See Note 6—Acquisitions and Consolidations—Acquisitions, for further discussion. These projects were previously owned by EME's affiliate, Edison Capital. Edison Mission Group is a subsidiary of Edison International and is the holding company for its wholly owned subsidiaries, Mission Energy Holding Company (MEHC) and Edison Capital. MEHC is the holding company of its wholly owned subsidiary EME. 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.

Stock-Based Compensation

EME's stock-based compensation plans primarily include the issuance of Edison International stock options and performance shares. 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 performance shares. Edison International has approximately 13.7 million shares remaining for future issuance under its stock-based compensation plans, which are described more fully in Note 12—Stock Compensation Plans.

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 Note 13—New Accounting Pronouncements, effective January 1, 2006, EME implemented a new accounting standard 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 vesting 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 vesting 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 vesting 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 $1 million for the nine months ended September 30, 2006. There would have been no significant changes for the third quarters of 2006 and 2005 and for the nine months ended September 30, 2005.

Total stock-based compensation expense (reflected in the caption "Administrative and general" on the consolidated statements of income) was $3 million and $8 million for the third quarters of 2006 and 2005, respectively, and $7 million and $20 million for the nine months ended September 30, 2006 and 2005, respectively. The income tax benefit recognized in the income statement was $1 million and $3 million for the third quarters of 2006 and 2005, respectively, and $3 million and $8 million for the nine months ended September 30, 2006 and 2005, respectively.

The following table illustrates the effect on net income if EME had used the fair value accounting method for the third quarter of 2005 and nine months ended September 30, 2005.

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
	(in millions)	
Net income, as reported	$ 200	$ 304
Add: stock-based compensation expense using the intrinsic value accounting method—net of tax	5	12
Less: stock-based compensation expense using the fair value accounting method—net of tax	(3)	(9)
Pro forma net income	$ 202	$ 307

Reclassifications

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.

Revisions

EME revised its Consolidated Statements of Cash Flows for the nine months ended September 30, 2005 to separately disclose the operating and investing portion of the cash flows attributable to its discontinued operations consistent with its Consolidated Statements of Cash Flow for the year ended December 31, 2005 included in EME's annual report on Form 10-K for the year ended December 31, 2005. EME had previously reported these amounts on a combined basis in its quarterly report on Form 10-Q for the nine months ended September 30, 2005.

Note 2. Inventory

Inventory is stated at the lower of weighted average cost or market. Inventory at September 30, 2006 and December 31, 2005 consisted of the following:

	September 30, 2006	December 31, 2005
	(in millions)	
Coal and fuel oil	$ 124	$ 77
Spare parts, materials and supplies	45	43
Total	$ 169	$ 120

Note 3. Short-term Investments

Held-to-Maturity Securities

At September 30, 2006 and December 31, 2005, EME had marketable debt securities that were classified as held-to-maturity and carried at amortized cost plus accrued interest which approximated their fair value.

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

	September 30, 2006	December 31, 2005
	(in millions)	
Commercial paper	$ 295	$ 99
Certificates of deposit	67	34
Time deposits	—	50
Corporate bonds	4	—
Total	$ 366	$ 183

Note 4. Refinancing

Credit Agreement

On June 15, 2006, EME replaced its $98 million credit agreement with a new credit agreement that provides for a $500 million senior secured revolving loan and letter of credit facility and matures on June 15, 2012. 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. As of September 30, 2006, $6 million of letters of credit were 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 September 30, 2006, 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 will be deposited. EME will be free to use these proceeds unless an event of default occurs under the credit facility.

Senior Notes Offering

On June 6, 2006, EME completed a private offering of $500 million aggregate principal amount of its 7.50% senior notes due June 15, 2013 and $500 million aggregate principal amount of its 7.75% senior notes due June 15, 2016. EME will pay interest on the senior notes on June 15 and December 15 of each year, beginning on December 15, 2006. The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount of, plus accrued and unpaid interest and liquidated damages, if any, on, 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.

EME used the net proceeds of the offering of the senior notes, together with cash on hand, to purchase $369 million in aggregate principal amount of its 10% senior notes due August 15, 2008 and $596 million in aggregate principal amount of its 9.875% senior notes due April 15, 2011. The net proceeds of the offering of the senior notes, together with cash on hand, were also used to pay related tender premiums, consent fees and accrued interest. EME recorded a $143 million loss on early extinguishment of debt during the second quarter of 2006.

Note 5. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of the following:

	Unrealized Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	Accumulated Other Comprehensive Income (Loss)
		(in millions)	
Balance at December 31, 2005	$ (210)	$ (1)	$ (211)
Current period change	324	(2)	322
Balance at September 30, 2006	$ 114	$ (3)	$ 111

Unrealized gains on cash flow hedges, net of tax, at September 30, 2006, include unrealized gains on commodity hedges related to Midwest Generation, LLC (Midwest Generation) and EME Homer City Generation L.P. (EME Homer City) futures and forward electricity contracts that qualify for hedge accounting. These gains arise because current forecasts of future electricity prices in the relevant markets are lower than the contract prices. The decrease in the unrealized losses during the nine months ended September 30, 2006 resulted from a decrease in market prices for power.

As EME's hedged positions for continuing operations are realized, approximately $68 million, after tax, of the net unrealized gains on cash flow hedges at September 30, 2006 are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized gains will offset 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, 2009.

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 gains (losses) of approximately $7 million and $(32) million during the third quarters of 2006 and 2005, respectively, and $(10) million and $(35) million during the nine months ended September 30, 2006 and 2005, respectively, representing the amount of cash flow hedges' ineffectiveness for continuing operations, reflected in net gains from price risk management and energy trading in EME's consolidated income statements.

Note 6. Acquisitions and Consolidations

Acquisitions

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. EME's historical financial statements have been adjusted for all periods presented to reflect the acquisition as though EME had always owned the projects. 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	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
		(in millions)	
Total operating revenues	$ 4	$ 3	$ 14
Loss before income taxes	(1)	(1)	(1)
Benefit for income taxes	(3)	(2)	(6)
Income from continuing operations	2	1	5

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).

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 the Wildorado Wind Project, which owns a 161 megawatt (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. As of September 30, 2006, a cash payment of $18 million had been made towards the purchase price. This project started construction in April 2006 and is scheduled for completion during April 2007, with total construction costs, excluding capitalized interest, estimated to be $270 million. 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.

Consolidations

Variable Interest Entities

In December 2003, the FASB re-issued Statement of Financial Accounting Standards Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46R). FIN 46R 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 FIN 46R, the primary beneficiary is the variable interest holder that absorbs a majority of expected losses; if no variable interest holder meets this 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.

EME completed a review of the application of FIN 46R to its subsidiaries and affiliates and concluded that it had significant variable interests in variable interest entities as defined in this Interpretation. As of September 30, 2006, 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 $365 million as of September 30, 2006.

Note 7. 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 a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as 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 and the project company was subsequently placed in liquidation. In response to its claim against the TXU subsidiary for damages from the termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the amount of the settlement remaining after payment of creditor claims. As creditor claims have been settled, EME has received to date payments of £13 million (approximately $24 million) in April 2005, £61 million (approximately $106 million) in the first quarter of 2006, and £9 million (approximately $16 million) in April 2006. The after-tax income attributable to the Lakeland project was none for both the third quarters of 2006 and 2005 and $83 million and $24 million for the nine months ended September 30, 2006 and 2005, respectively. Beginning in 2002, EME reported the Lakeland project among discontinued operations and accounts for its ownership of Lakeland Power on the cost method, with earnings being 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. Summarized results of discontinued operations are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Total operating revenues	$ —	$ —	$ —	$ —
Income (loss) before income taxes and minority interest	(2)	(2)	117	20
Provision (benefit) for income taxes	—	(29)	42	(30)
Minority interest	—	—	—	—
Income (loss) from operations of discontinued foreign subsidiaries	(2)	27	75	50
Gain on sale before income taxes	—	—	—	9
Gain on sale after income taxes	—	—	—	5

Assets of $1 million and liabilities of $4 million associated with the discontinued operations are included on the consolidated balance sheet at December 31, 2005 in other long-term assets and other long-term liabilities, respectively.

Note 8. Employee Benefit Plans

Pension Plans

EME previously disclosed in its financial statements for the year ended December 31, 2005 that it expected to contribute $14 million to its pension plans in 2006. As of September 30, 2006, $11 million in contributions have been made. Additional funding in 2006 could be lower than anticipated, depending on the funded status at year-end and tax-deductible funding limitations.

Components of pension expense are:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Service cost	$ 4	$ 5	$ 13	$ 14
Interest cost	2	2	6	6
Expected return on plan assets	(1)	(1)	(4)	(4)
Net amortization and deferral	—	—	—	1
Total expense	$ 5	$ 6	$ 15	$ 17

Postretirement Benefits Other Than Pensions

EME previously disclosed in its financial statements for the year ended December 31, 2005 that it expected to contribute $1 million to its postretirement benefits other than pensions in 2006. As of September 30, 2006, $0.6 million in contributions have been made. EME continues to expect to contribute $1 million to its postretirement benefits other than pensions in 2006.

Components of postretirement benefits expense are:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Service cost	$ 1	$ 1	$ 2	$ 2
Interest cost	1	1	3	3
Amortization of unrecognized prior service costs	—	—	(1)	(1)
Amortization of unrecognized loss	—	—	1	—
Total expense	$ 2	$ 2	$ 5	$ 4

Note 9. Income Taxes

EME's income tax provision from continuing operations was $135 million and $123 million for the nine months ended September 30, 2006 and 2005, respectively. Income tax benefits are recognized pursuant to a tax-allocation agreement with Edison International. During the nine months ended September 30, 2006 and 2005, EME recognized $12 million and $5 million, respectively, of production tax credits related to wind projects, more fully described below, 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 instead as a reduction of income taxes during the second quarter of 2005.

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. Production tax credits are recognized by EME when the corresponding electricity is produced.

Note 10. Commitments and Contingencies

Contractual Obligations

Long-term Debt

EME's long-term debt maturities as of September 30, 2006 are (in millions):

October through December 2006	$ 2
2007	133
2008	51
2009	613
2010	15

These amounts have been updated primarily to reflect EME's financing activities completed during the second quarter of 2006. See Note 4—Refinancing.

Capital Improvements

At September 30, 2006, EME's subsidiaries had firm commitments to spend approximately $230 million during the remainder of 2006 and $147 million in 2007 on capital and construction expenditures. The majority of these expenditures relate to the construction of the 161 MW Wildorado wind project and four other wind projects totaling 181 MW. Also included are expenditures for boiler header replacement, dust collection and mitigation system and various other smaller projects. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

Commercial Commitments

Introduction

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, standby letters of credit, guarantees of debt and indemnifications.

Turbine Commitments

At September 30, 2006, in connection with wind projects in development, EME had entered into agreements with turbine vendors securing 223 turbines (407 MW) with remaining commitments of $20 million in 2006 and $335 million in 2007. In addition, EME has options, exercisable through December 1, 2006, to purchase another 32 turbines (80 MW) for delivery in 2007.

At September 30, 2006, in connection with thermal projects in development, EME had entered into an agreement for the purchase of five gas turbines and related equipment for an aggregate purchase price of approximately $140 million with remaining commitments of $38 million in 2006, $76 million in 2007 and $3 million in 2008. In addition, under the terms of this agreement, EME obtained an option, exercisable through January 26, 2007, to purchase five additional gas turbines and related equipment.

Standby Letters of Credit

At September 30, 2006, standby letters of credit aggregated $43 million and were scheduled to expire as follows: $22 million in 2006 and $21 million in 2007.

Guarantees and Indemnities

Tax Indemnity Agreements—

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

Indemnities Provided as Part of the Acquisition of the Illinois Plants—

In connection with the acquisition of the Illinois Plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison take 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 Company 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 existing asbestos claims and expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were approximately 176 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at September 30, 2006. Midwest Generation had recorded a $66 million liability at September 30, 2006 related to this matter.

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

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

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale. 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. Payments would be triggered under this indemnity by a claim from the sellers. 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. During the second quarter of 2006, EME paid $34 million 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. 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 September 30, 2006, EME had recorded a liability of $96 million related to these matters.

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

Guarantee of Brooklyn Navy Yard Contractor Settlement Payments—

On March 31, 2004, EME completed the sale of 100% of the stock of Mission Energy New York, Inc., which held a 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners, L.P. (referred to as Brooklyn Navy Yard), to BNY Power Partners LLC. Brooklyn Navy Yard owns a 286 MW gas-fired cogeneration power plant in Brooklyn, New York. In February 1997, the construction contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard. A settlement agreement was executed on January 17, 2003, and all litigation has been dismissed. EME agreed to indemnify Brooklyn Navy Yard and, in connection with the sale of EME's interest in Brooklyn Navy Yard, BNY Power Partners for any payments due under this settlement agreement, which are scheduled through January 2007. At September 30, 2006, EME had recorded a liability of $4 million related to this indemnity.

Capacity Indemnification Agreements—

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power sales agreements. In addition, a subsidiary of EME has guaranteed the obligations of Sycamore Cogeneration Company under its project power sales agreement to repay capacity payments to the project's power purchaser in the event that the project unilaterally terminates its performance or reduces its electric power producing capability during the term of the power sales agreement. The obligations under the indemnification agreements as of September 30, 2006, if payment were required, would be $109 million. EME has not recorded a liability related to these indemnities.

Subsidiary Guarantee for Performance of Unconsolidated Affiliate—

A subsidiary of EME has guaranteed the obligations of an unconsolidated affiliate to make payments to a third party for power delivered under a fixed-price power sales agreement. This agreement runs through 2007. EME believes there is sufficient cash flow to pay the power suppliers, assuming timely payment by the power purchasers. Due to the nature of this indemnity, a maximum potential liability cannot be determined. To the extent EME's subsidiary would be required to make payments under the guarantee, EME's subsidiary and EME are indemnified by Peabody Energy Corporation pursuant to the 2000 Purchase and Sale Agreement for Citizens Power LLC. EME's subsidiary has not recorded a liability related to this indemnity.

Contingencies

FERC Notice Regarding Investigatory Proceeding against EMMT

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

MISO Revenue Sufficiency Guarantee Charges

On April 25, 2006, the FERC issued an order regarding the Midwest Independent Transmission System Operator's, or MISO's, "Revenue Sufficiency Guarantee" charges, or RSG charges. The MISO's business practice manuals and other instructions to market participants have stated, since the implementation of market operations on April 1, 2005, that RSG charges will not be imposed on offers to supply power not supported by actual generation (also known as virtual supply offers). However, some market participants raised questions about the language of the MISO's tariff concerning that issue and, in October 2005, the MISO submitted to the FERC proposed tariff revisions clarifying its tariff to reflect its business practices with respect to RSG charges and filed corrected tariff sheets exempting virtual supply from RSG charges. In an April 25 decision, the FERC interpreted the MISO's tariff to require that virtual supply offers must be included in the calculation of the RSG charges and that, to the extent that the MISO did not charge virtual supply offers for RSG charges, it violated the terms of its tariff. The FERC order then proceeded to require the MISO to recalculate the RSG charges back to April 1, 2005, and to make refunds to customers, with interest, reflecting the recalculated charges. As a result of the order, it is possible that the MISO would attempt to impose retroactively RSG charges on those who submitted virtual supply offers during the recalculation period. Edison Mission Marketing & Trading, or EMMT, made virtual supply offers in the MISO during this period on which no RSG charges were imposed, and thus had potential exposure to such a claim for refunds from the MISO. EMMT and other parties requested rehearing of the April 25th order. On May 17, 2006, FERC issued a notice extending the time for the MISO to comply with the requirements of the April 25th order, including the requirement to refund to customers any amounts due, until after the date of issuance of an order on rehearing. On October 26, 2006, FERC issued an Order on Rehearing, declining to impose refunds. Consequently, EMMT is not required to make refunds to account for the imposition of RSG charges back to April 1, 2005.

Midway-Sunset Cogeneration Company

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

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

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

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

Tax Matters

EME is, and may in the future be, under examination by tax authorities in varying tax jurisdictions with respect to positions it takes in connection with the filing of its tax returns. Matters raised upon audit may involve substantial amounts, which, if resolved unfavorably, an event not currently anticipated, could possibly be material. However, in EME's opinion, it is unlikely that the resolution of any such matters will have a material adverse effect upon EME's financial condition or results of operations.

Litigation

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

Insurance

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed, resulting in a suspension of operations at this unit. EME Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. The main transformer failure will result in claims under EME Homer City's property and business interruption insurance policies. At September 30, 2006, EME Homer City had a $17 million receivable, of which $11 million relates to business interruption insurance coverage and has been reflected in other income (expense), net in EME's consolidated income statements.

Environmental Matters and Regulations

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. 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. The initial State Implementation Plans (SIP) for the Clean Air Interstate Rule were to be submitted during September 2006; however, the US EPA has extended this date, thereby allowing the states to submit abbreviated SIPs by March 31, 2007. Compliance with these regulations will affect the costs and the manner in which EME conducts its business, and will require EME to make substantial additional capital expenditures. There is no assurance that EME would be able to recover these increased costs from its customers or that EME's financial position and results of operations would not be materially adversely affected as a result.

Typically, environmental laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals prior to construction, operation or modification of a project or generating facility. Meeting all the necessary requirements can delay or sometimes prevent the completion of a proposed project, as well as require extensive modifications to existing projects, which may involve significant capital expenditures. Failure to comply with applicable environmental laws may subject a project's owner or operator to injunctive relief or penalties and fines imposed by regulatory authorities.

With respect to potential liabilities arising under Comprehensive Environmental Response, Compensation and Liability Act of 1980, commonly referred to as 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 had accrued approximately

$3 million as of September 30, 2006 for estimated environmental investigation and remediation costs for the Illinois Plants. This estimate is based upon the number of sites, the scope of work and the estimated costs for environmental activity where such expenditures could be reasonably estimated. Future estimated costs may vary based on changes in regulations or requirements of federal, state, or local governmental agencies, changes in technology, and actual costs of disposal. In addition, future remediation costs will be affected by the nature and extent of contamination discovered at the sites that requires remediation. Given the prior history of the operations at its facilities, EME cannot be certain that the existence or extent of all contamination at its sites has been fully identified. However, based on available information, management believes that future costs in excess of the amounts disclosed on all known and quantifiable environmental contingencies will not be material to EME's financial position. See "Note 16. Commitments and Contingencies—Environmental Matters and Regulations" in EME's financial statements included in its annual report on Form 10-K for the year ended December 31, 2005 for a more complete discussion of EME's environmental contingencies.

Note 11. Supplemental Statements of Cash Flows Information

	Nine Months Ended September 30,	
	2006	**2005**
	(in millions)	
Cash paid (received)		
Interest (net of amount capitalized)	$ 177	$ 182
Income taxes	16	(41)
Cash payments under plant operating leases	292	247
Details of assets acquired		
Fair value of assets acquired	$ 29	$ —
Liabilities assumed	—	—

During the first nine months of 2006, EME accrued $11 million in connection with the purchase price of the Wildorado wind project due upon completion of construction. In addition, 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.

Note 12. Stock Compensation Plans

Stock Options

Under various plans, EME may grant stock options at exercise prices equal to the average of high and low price at the grant date and other awards related to or with a value derived from Edison International 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 vesting period, except for awards granted to retirement-eligible participants, as discussed in Note 1—General—Stock-Based Compensation. Stock-based compensation expense associated with stock options was $2 million and $6 million for the third quarter of 2006 and nine months ended September 30, 2006, respectively. Under prior accounting rules, there was no comparable expense recognized for the same periods in 2005. See Note 1—General—Stock-Based Compensation, for further discussion.

Beginning with awards made in 2003, stock options accrue dividend equivalents for the first five years of the option term. Unless transferred to non-qualified 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 grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Expected terms (in years)	9 to 10	9 to 10	9 to 10	9 to 10
Risk-free interest rate	4.5%-4.7%	4.1%-4.2%	4.3%-4.7%	4.1%-4.3%
Expected dividend yield	2.5%-2.8%	2.1%-2.5%	2.4%-2.8%	2.1%-3.1%
Weighted-average expected dividend yield	2.6%	2.4%	2.4%	3.1%
Expected volatility	15.9%-17.2%	15.8%-18.1%	15.9%-17.5%	15.8%-19.6%
Weighted-average volatility	16.4%	18.0%	16.3%	19.5%

The expected term of options granted is based on the actual remaining contractual term of the options. 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 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:

		Weighted Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2005	3,626,365	$ 22.06		
Granted	411,086	44.08		
Transferred to affiliates	(298,647)	21.83		
Forfeited	(30,550)	29.45		
Exercised	(523,895)	19.93		
Outstanding at September 30, 2006	3,184,359	$ 25.20		
Vested and expected to vest at September 30, 2006	3,052,034	$ 24.95	6.87	$ 50,251,748
Exercisable at September 30, 2006	1,545,795	$ 20.05	5.77	$ 33,025,910

The weighted-average fair value of options granted during the quarters ended September 30, 2006 and 2005 was $13.53 and $13.88, respectively. The weighted-average fair value of options granted for the nine months ended September 30, 2006 and 2005 was $14.41 and $11.73, respectively. The total intrinsic value of options exercised during the quarters ended September 30, 2006 and 2005 was

$3 million and $4 million, respectively. The total intrinsic value of options exercised for both the nine months ended September 30, 2006 and 2005 was $14 million. At September 30, 2006, there was $10 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 2 years. The fair value of options vested during the quarters ended September 30, 2006 and 2005, was zero. The fair value of options vested during the nine-month periods ended September 30, 2006 and 2005, was $1 million and $2 million, respectively.

The amount of cash used by Edison International to settle stock options exercised by EME employees was $7 million for both the third quarters of 2006 and 2005, and $26 million for both the nine months ended September 30, 2006 and 2005. Cash received by Edison International from stock options exercised by EME employees for the quarters ended September 30, 2006 and 2005 was $4 million and $3 million, respectively, and for both the nine months ended September 30, 2006 and 2005 was $12 million. The estimated tax benefit from options exercised was $5 million and $6 million for the nine months ended September 30, 2006 and 2005, respectively.

Performance Shares

A target number of contingent performance shares were awarded to executives in January 2004, January 2005 and March 2006, and vest at the end of December 2006, 2007 and 2008, respectively. Dividend equivalents associated with these performance shares accumulate without interest and will be payable in cash following the end of the performance period when the performance shares are paid, although Edison International has discretion to pay certain dividend equivalents in Edison International common stock. 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 vesting period based on the fair values determined, except for awards granted to retirement-eligible participants, as discussed in "Stock-Based Compensation" in Note 1—General—Stock-Based Compensation. Stock-based compensation associated with performance shares was $1 million and $6 million for the quarters ended September 30, 2006 and 2005, respectively, and $2 million and $15 million for the nine months ended September 30, 2006 and 2005, respectively. No cash was used to settle performance shares classified as equity awards in the third quarters of 2006 and 2005, and $10 million and $4 million was used for the nine months ended September 30, 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 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 and expected volatility used to determine the grant date fair values for the 2006 and 2005 performance shares classified as share-based equity awards was 4.1% and 16.2%, respectively, and 2.7% 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 September 30, 2006 was 4.7% and 16.5%, respectively.

The total intrinsic value of performance shares settled during the quarters ended September 30, 2006 and 2005 was zero. The total intrinsic value of performance shares settled during the nine months ended September 30, 2006 and 2005 was $19 million and $8 million, respectively, which included cash paid to settle the performance shares classified as liability awards of $8 million and $4 million for the nine months ended September 30, 2006 and 2005, respectively. At September 30, 2006, there was $2 million (based on the September 30, 2006 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 values of performance shares vested during the quarters and nine-month periods ended September 30, 2006 and 2005, was zero.

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, 2005	67,530	$ 38.63
Granted	16,599	52.19
Forfeited	(1,266)	39.36
Nonvested at September 30, 2006	82,863	$ 41.34

The weighted-average grant-date fair value of performance shares classified as equity awards granted during the quarter ended September 30, 2005 was $46.09.

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, 2005	67,547	
Granted	16,618	
Forfeited	(1,267)	
Nonvested at September 30, 2006	82,898	$ 87.17

Note 13. New Accounting Pronouncements

Statement of Financial Accounting Standards No. 123(R)

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. EME implemented the new standard in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, the new accounting standard 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. The new accounting standard resulted in the recognition of expense for all stock-based compensation awards. Prior to January 1, 2006, EME used the intrinsic value method of accounting, which resulted in no recognition of expense for Edison International stock options. Prior to adoption of the new accounting standard, 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. The new accounting standard 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 $5 million excess tax benefit is classified as a financing cash inflow in 2006.

Due to the adoption of this new accounting standard, EME recorded a cumulative effect adjustment that increased net income by approximately $0.4 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

FASB Staff Position FIN 46(R)-6

In April 2006, the FASB issued Staff Position FIN 46(R)-6, "Determining Variability to be Considered in Applying FIN 46(R)." FIN 46(R)-6 states that the variability to be considered in applying FIN 46(R) shall be based on an analysis of the design of the entity following a two-step process. The first step is to analyze the nature of the risks in the entity. The second step would be to determine the purpose(s) for which the entity was created and determine the variability (created by the risks identified in Step 1) the entity is designed to create and pass along to its interest holders. The guidance in this FASB Staff Position is effective prospectively beginning July 1, 2006, although companies have until December 31, 2006 to elect retrospective applications. EME has not yet selected a transition method. Applying the guidance of FIN 46(R)-6 had no effect on EME's consolidated financial statements for the three months ended September 30, 2006.

Statement of Financial Accounting Standards Interpretation No. 48

In July 2006, the FASB issued Statement of Financial Accounting Standards Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," that clarifies the accounting for uncertain tax positions. An enterprise would be required 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. The effective date applicable to EME is January 1, 2007. EME is currently assessing the potential impact of the interpretation on its financial condition.

Statement of Financial Accounting Standards No. 157

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

Statement of Financial Accounting Standards No. 158

In September 2006, the FASB issued SFAS No. 158, which amends the accounting by employers for defined benefit pension plans and postretirement benefits other than pensions. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension or other postretirement plan as an asset or liability in their balance sheet; the asset or liability is offset through other comprehensive income. The standard 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. EME will adopt SFAS No. 158 prospectively on December 31, 2006. Had SFAS No. 158 been effective as of December 31, 2005, EME would have recorded additional postretirement benefit liabilities of $22 million and a reduction to accumulated other comprehensive income (a component of shareholder's equity) of $13 million, net of tax. EME is currently assessing the impact of this standard, but does not expect a material effect on its consolidated financial statements or its financial covenants.

Staff Accounting Bulletin No. 108

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. The new guidance requires additional quantitative testing to determine whether a misstatement is material. EME will implement SAB No. 108 for the filing of its 2006 Annual Report on Form 10-K. EME does not expect that SAB No. 108 will have a material effect on its consolidated financial statements.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Management's Discussion and Analysis of Financial Condition and Results of Operations (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 report, or that refers to or incorporates this report, may also contain forward-looking statements. In this quarterly report on Form 10-Q, 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, 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 and environmental regulations that could require additional expenditures or otherwise affect EME's cost and manner of doing business;*
- *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 difficulty of predicting wholesale prices, transmission congestion, energy demand, and other activities in 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;*
- *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*
- *the continued participation by EME and its subsidiaries in tax-allocation and payment agreements with their affiliates.*

Additional information about risks and uncertainties, including more detail about the factors described above, is contained throughout this MD&A and in the "Risk Factors" section included in Part I, Item 1A of EME's Annual Report on Form 10-K for the year ended December 31, 2005. Readers are urged to read this entire quarterly report on Form 10-Q 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 discusses material changes in the results of operations, financial condition and other developments of EME since December 31, 2005, and as compared to the third quarter of 2005 and nine months ended September 30, 2005. This discussion presumes that the reader has read or has access to the MD&A included in Item 7 of EME's annual report on Form 10-K for the year ended December 31, 2005.

This MD&A is presented in four sections:

MANAGEMENT'S OVERVIEW; CRITICAL ACCOUNTING ESTIMATES

Management's Overview

Results of Operations

Net income is comprised of the following components:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Income from continuing operations	198	173	230	249
Income (loss) from discontinued operations	(2)	27	75	55
Net Income	$ 196	$ 200	$ 305	$ 304

EME's increase in income from continuing operations in the third quarter of 2006 was primarily attributable to higher earnings at the Homer City facilities and a $34 million after-tax impairment on EME's equity investment in the March Point project recorded during the third quarter of 2005. Partially offsetting these increases was lower energy trading income from EMMT. The year-to-date decrease in income from continuing operations was primarily due to loss on early extinguishment of debt and lower energy trading income from EMMT. Partially offsetting these decreases were higher earnings at the Illinois Plants and the March Point impairment loss recorded during 2005.

EME's income from discontinued operations during the nine months ended September 30, 2006 and 2005 was primarily related to distributions authorized by the liquidators of the Lakeland power project. EME has received a total of $122 million of distributions in 2006 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. 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.

Hedging Activities

In September 2006, the first Illinois power procurement auction was held by Commonwealth Edison under rules approved by the Illinois Commerce Commission. Pursuant to this auction, EMMT entered into two load requirements services contracts. Under the terms of these agreements, Midwest Generation expects to deliver through EMMT electricity together with capacity and specified ancillary, transmission and load following services necessary to serve a portion of Commonwealth Edison's residential and small commercial customer load. The estimated megawatt-hours for 2007, 2008 and 2009 under these energy supply agreements are 8.5 million, 6.2 million and 1.8 million, respectively. The amount of power sold under these agreements can vary significantly with variations in load. See "Market Risk Exposures—Commodity Price Risk—Energy Price Risk Affecting Sales From the Illinois Plants" for further discussion of Midwest Generation's hedge position.

Environmental Developments Regarding Emissions

During the third quarter of 2006, Ameren Corporation and Dynegy Inc. announced agreements with the Illinois Environmental Protection Agency to reduce mercury, NOx, SO2 and fine particulates at their Illinois coal-fired power plants. These agreements take the form of so-called Multi-Pollutant Standards, or MPS, as part of a rule related to mercury emissions adopted on November 2, 2006, by the Illinois Pollution Control Board related to mercury emissions. Under the rule, Ameren and Dynegy will be permitted to meet a less stringent Illinois standard with respect to mercury emissions in exchange for agreeing to reduce the emissions of other pollutants in accordance with the MPS. As adopted, the rule will permit any company, including Midwest Generation, to opt into the MPS by December 2007.

In a separate rule making procedure, the Illinois EPA has begun the process of developing a SIP to implement the federal Clean Air Interstate Rule which is to be submitted to the US EPA by March 31, 2007. It has also begun to develop SIPs to meet the National Air Quality Standards for 8-hour ozone and fine particulates and regional haze. These SIPs are due to be submitted to the US EPA in 2007 and 2008.

The Illinois Plants will need to be in compliance with these SIPs when they finally come into effect. The costs to add appropriate environmental equipment, which could include flue gas desulfurization systems, selective catalytic reduction systems, bag-houses, sorbent injection systems, or other environmental equipment, could be significant. For certain of the units within EME's Illinois Plants, the capital costs of adding equipment to achieve compliance may not be economically justifiable and could result in the decommissioning of some individual units.

EME considers many factors in connection with the making of capital improvements or plant decommissionings including, among others: an assessment of new technologies, the cost and performance of environmental equipment (including changes in labor and materials costs), and the availability of cap and trade programs and the projected prices of emissions allowances. The type of coal to be used can also have a significant impact on the amount of emissions from coal-fired power plants and hence the type of controls required. With respect to technology, EME is currently testing the use of sorbent injection technology for the removal of mercury at several of its plants. Decisions made by EME also will be affected by the expected future spread between projected power and coal prices. In view of the many factors involved and in the absence of rules in definitive form, EME has not at this time determined what actions it may take to provide for optimal compliance with these environmental regulations, including whether to opt into the MPS. However, it is likely that any optimized plan will require additional capital costs for environmental retrofits of the Illinois coal units and that the amount of these costs will be material. See "Liquidity and Capital Resources—Environmental Matters and Regulations—State-Illinois" for further discussion of environmental developments.

Business Development

Wind Projects

EME has undertaken a number of activities with respect to new wind projects, including:

- Completion in January 2006 of the purchase of development rights for the Wildorado wind project for $29 million. This project started construction in April 2006 and is scheduled for completion during April 2007, with total construction costs estimated to be $270 million. Upon completion, power from the project will be sold under a twenty-year power purchase agreement to Southwestern Public Service.
- Releasing for construction four wind projects totaling 181 MW. Construction costs are estimated to be $252 million with completion scheduled for the spring of 2007.
- Securing a supply of 223 turbines for 407 MW of additional wind projects which are expected to be developed and constructed by the end of 2007.

Also, in April 2006, EME received, as a capital contribution, ownership interests in a 192 MW portfolio of wind projects (EME's share is 176 MW) located in Iowa and Minnesota. 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.

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. Generally, it is expected that thermal projects in which EME invests will sell electricity under long-term power purchase contracts. EME has responded to several requests for proposals to build or acquire generation and recently submitted two indicative bids in response to the request for offers for electricity supply from new generation resources announced by SCE in July 2006. In connection with these thermal development activities, in September 2006, EME entered into an agreement for the purchase of five gas turbines and related equipment for an aggregate purchase price of approximately $140 million. In addition, under the terms of this agreement, EME obtained an option, exercisable through January 26, 2007, to purchase five additional gas turbines and related equipment.

In June 2006, subsidiaries of EME and BP America Inc. formed Carson Hydrogen Power LLC for the development of a power project to be located in Carson, California. Carson Hydrogen is a development stage enterprise for a planned industrial gasification project that will integrate proven gasification, power generation and enhanced oil recovery technologies. Carson Hydrogen is conducting preliminary development, including engineering, financial analysis and commercial arrangements, required for project implementation.

Financing Activities

On June 6, 2006, EME completed a private offering of $500 million of its 7.50% senior notes due 2013 and $500 million of its 7.75% senior notes due 2016. The proceeds of the offering were used, together with cash on hand, to purchase substantially all of EME's outstanding 10% senior notes due 2008 and 9.875% senior notes due 2011. In connection with the purchase of these notes, EME recorded a $143 million loss on early extinguishment of debt in the second quarter of 2006.

On June 15, 2006, EME entered into a new credit agreement providing for $500 million in revolving loan and letter of credit capacity to be used for general corporate purposes including credit support for the hedging and trading activities of EME and its subsidiaries. The new credit agreement replaces EME's $98 million credit agreement.

ERP Initiative

EME has commenced a new initiative as part of an Edison International enterprise-wide project to implement an integrated enterprise resource planning (ERP) application from SAP during the next two years. The implementation of this application will replace EME's existing financial, human resources, materials management, and fuel management information systems with SAP's integrated ERP application. The objective of this initiative is to improve the efficiency and effectiveness of EME's operational systems and enhance the transparency of information throughout the company.

Critical Accounting Estimates

For a discussion of EME's critical accounting estimates, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates" of EME's annual report on Form 10-K for the year ended December 31, 2005.

RESULTS OF OPERATIONS

Introduction

This section discusses operating results for the third quarters of 2006 and 2005 and nine months ended September 30, 2006 and 2005, and 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 power generated from the Illinois Plants and the Homer City facilities. Intercompany interest expense and income between EME and its consolidated subsidiaries have been eliminated in the following project results, except as described below with respect to loans provided to EME from a wholly owned subsidiary, Midwest Generation, and loans from Midwest Generation to EMMT for margining. Equity in income from unconsolidated affiliates relates to energy projects accounted for under the equity method. EME recognizes its proportional share of the income or loss of such entities.

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 third quarters of 2006 and 2005 and nine months ended September 30, 2006 and 2005 together with discussions of the contributions by specific projects and of other significant factors affecting these results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Project Earnings (Losses)(1)				
Consolidated operations				
Illinois Plants	$ 191	$ 187	$ 343	$ 297
Homer City	69	33	102	83
Energy Trading(2)	54	84	109	125
San Juan Mesa	—	—	5	—
Storm Lake	—	(1)	3	1
Other	—	(1)	—	(1)
Unconsolidated affiliates				
Big 4 projects	62	73	117	134
Sunrise	29	29	32	31
March Point	—	5	—	9
Impairment loss on equity method investment	—	(55)	—	(55)
Doga	(7)	(2)	(3)	3
Other	5	6	8	11
	403	358	716	638
Corporate interest income	21	13	58	37
Corporate interest expense	(63)	(67)	(193)	(203)
Corporate administrative and general	(26)	(26)	(75)	(85)
Gain on sale of assets	—	—	4	—
Loss on early extinguishment of debt	—	—	(143)	(4)
Other income (expense), net	—	—	10	(6)
	$ 335	$ 278	$ 377	$ 377

(1) Project earnings are equal to income from continuing operations before income taxes, except for production tax credits. Accordingly, project earnings for the wind projects include $3 million and $1 million of production tax credits for the third quarters of 2006 and 2005, respectively, and $12 million and $5 million for the nine months ended September 30, 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 generally accepted accounting principles (GAAP), production tax credits generated by the wind projects are recorded as a reduction in income taxes. Accordingly, project earnings (losses) represent a non-GAAP performance measure which may not be comparable to those of other companies. Management believes that inclusion of production tax credits in project earnings for wind projects is more meaningful for investors as federal and state subsidies are an integral part of the economics of these projects. The following table reconciles the total project earnings as shown above with income from continuing operations before income taxes under GAAP:

	Three Months Ended September 30,		Nine Months Ended September 30	
	2006	2005	2006	2005
	(in millions)			
Project earnings	$ 335	$ 278	$ 377	$ 377
Less: Production tax credits	(3)	(1)	(12)	(5)
Income from continuing operations before income taxes	$ 332	$ 277	$ 365	$ 372

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

Earnings from Consolidated Operations

Illinois Plants

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Operating Revenues				
Energy revenues	$ 428	$ 438	$ 1,027	$ 1,009
Capacity revenues	7	10	20	24
Other revenues	3	3	7	6
Net losses from price risk management	—	(33)	(4)	(44)
Total operating revenues	438	418	1,050	995
Operating Expenses				
Fuel	122	107	288	279
Gain on sale of emission allowances(1)	—	—	(6)	—
Plant operations	74	75	270	266
Plant operating leases	19	19	56	56
Depreciation and amortization	25	25	75	75
Asset impairment charges	—	—	—	7
Administrative and general	7	1	19	10
Total operating expenses	247	227	702	693
Operating Income	191	191	348	302
Other Income (Expense)				
Interest income on note receivable from EME	30	28	86	85
Interest expense and other	(30)	(32)	(91)	(90)
Total other income (expense)	—	(4)	(5)	(5)
Income Before Taxes	$ 191	$ 187	$ 343	$ 297
Statistics				
Coal-Fired Generation(2)				
Generation (in GWh)	8,429	8,137	21,167	22,366
Equivalent availability(3)	89.6%	87.9%	80.9%	76.8%
Capacity factor(4)	68.0%	65.7%	57.6%	60.8%
Load factor(5)	75.9%	74.7%	71.2%	79.2%
Forced outage rate(6)	7.0%	9.4%	5.7%	9.0%
Average energy price/MWh	$ 50.72	$ 53.85	$ 48.54	$ 45.12
Average fuel costs/MWh	$ 14.12	$ 13.16	$ 13.53	$ 12.50

(1) EME recorded $6 million of intercompany profit during the first quarter of 2006 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.

(2) This table summarizes key performance measures related to coal-fired generation, which represents the majority of the operations of the Illinois Plants.

(3) The equivalent availability factor is defined as the number of megawatt-hours the coal plants are available to generate electricity divided by the product of the capacity of the coal plants (in megawatts) 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) Capacity factor is defined as the actual number of megawatt-hours generated by the coal plants divided by the product of the capacity of the coal plants (in megawatts) and the number of hours in the period.

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

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

Earnings for the third quarter of 2006 increased $4 million, compared to the third quarter of 2005, primarily due to decreased losses related to price risk management activities mostly offset by lower energy margin (energy revenues less fuel expenses). Although generation in the third quarter of 2006 was higher than in the third quarter of 2005, energy margin decreased primarily due to a 6% decrease in average energy prices and higher coal costs driven by scheduled price increases.

Earnings for the nine months ended September 30, 2006 increased $46 million, compared to the corresponding period of 2005, primarily due to higher energy margin driven by higher average energy prices, decreased losses related to price risk management activities, recognition of income in 2006 from the sale of emission allowances to the Homer City facilities and an asset impairment charge recorded during the second quarter of 2005 primarily associated with a redefined capital program related to coal dust mitigation.

Losses from price risk management activities are due to price changes on power contracts that did not qualify for hedge accounting under SFAS No. 133. At September 30, 2006, cumulative unrealized losses of $7 million (pre-tax) have been recognized on hedge contracts that pertain to the remainder of 2006 through 2009. See "Market Risk Exposures—Commodity Price Risk" for more information regarding forward market prices.

The earnings of the Illinois Plants included interest income of $30 million and $28 million for the third quarters of 2006 and 2005, respectively, and $86 million and $85 million for the nine months ended September 30, 2006 and 2005, respectively, related to loans to EME. In August 2000, Midwest Generation, which owns or leases the Illinois Plants, entered into a sale-leaseback transaction of the Powerton-Joliet facilities. The proceeds from the sale of these facilities were loaned to EME, which also provided a guarantee of the related lease obligations of Midwest Generation. The Powerton-Joliet sale-leaseback is recorded as an operating lease for accounting purposes.

Homer City

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Operating Revenues				
Energy revenues	$ 174	$ 185	$ 451	$ 473
Capacity revenues	4	5	10	14
Other revenues	1	—	5	—
Net gains (losses) from price risk management	20	(22)	7	(26)
Total operating revenues	199	168	473	461
Operating Expenses				
Fuel(1)	84	84	213	208
Gain on sale of emission allowances(2)	(7)	—	(7)	—
Plant operations	23	21	86	80
Plant operating leases	25	25	76	76
Depreciation and amortization	4	4	12	12
Administrative and general	2	3	4	7
Total operating expenses	131	137	384	383
Operating Income	68	31	89	78
Other Income (Expense)				
Interest and other income	2	2	14	6
Interest expense	(1)	—	(1)	(1)
Total other income (expense)	1	2	13	5
Income Before Taxes	$ 69	$ 33	$ 102	$ 83
Statistics				
Generation (in GWh)	3,664	4,060	9,052	10,697
Equivalent availability(3)	91.9%	98.7%	79.4%	88.0%
Capacity factor(4)	87.9%	97.4%	73.2%	86.4%
Load factor(5)	95.6%	98.7%	92.1%	98.2%
Forced outage rate(6)	5.8%	0.2%	16.9%	3.6%
Average energy price/MWh	$ 47.37	$ 45.45	$ 49.78	$ 44.17
Average fuel costs/MWh	$ 22.92	$ 20.70	$ 23.58	$ 19.43

(1) Included in fuel costs were $9 million and $22 million during the third quarters of 2006 and 2005, respectively, and $30 million and $51 million during the nine months ended September 30, 2006 and 2005, respectively, related to the net cost of SO2 emission allowances. See "Market Risk Exposures—Commodity Price Risk—Emission Allowances Price Risk" for more information regarding the price of SO2 allowances.

(2) EME recorded $7 million of intercompany profit during the third quarter of 2006 on emission allowances sold by the Homer City facilities to the Illinois Plants in the first quarter of 2006 but not used by the Illinois Plants until the third quarter of 2006.

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

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

Earnings from Homer City increased $36 million and $19 million for the third quarter of 2006 and nine months ended September 30, 2006, respectively, compared to the corresponding periods of 2005. The third quarter increase is primarily attributable to changes in net gains (losses) from price risk management activities and recognition of income in the third quarter of 2006 from the sale of emission allowances to the Illinois Plants. The 2006 year-to-date increase is primarily attributable to changes in net gains (losses) from price risk management activities, recognition of income in 2006 from the sale of emission allowances and estimated insurance recovery related to the Unit 3 outage described below. Partially offsetting these increases were lower energy margin and higher plant operating costs in 2006 due to an unplanned outage at Unit 3. 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 the first nine months of 2006.

Homer City Unit 3 Outage—

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed resulting in a suspension of operations at this unit. Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. Homer City has adjusted its previously planned outage schedules for Unit 3 and the other Homer City units in order to minimize to the extent practicable overall outage activities for all units through the first half of 2007. The main transformer failure will result in claims under Homer City's property and business interruption insurance policies. At September 30, 2006, Homer City had a $17 million receivable related to these claims. Resolution of the claims is subject to a number of uncertainties, including computations of the lost profit during the outage period.

Price Risk Management—

Homer City recorded gains (losses) of approximately $8 million and $(32) million during the third quarters of 2006 and 2005, respectively, and $(8) million and $(35) million during the nine months ended September 30, 2006 and 2005, respectively, representing the amount of cash flow hedges' ineffectiveness. Gains (losses) related to the ineffective portion of hedge contracts were primarily due 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 and the settlement point for sales into PJM from the Homer City facilities). Also included in net gains (losses) from price risk management activities are economic hedges that did not qualify for hedge accounting under SFAS No. 133 of $12 million and $10 million in the third quarters of 2006 and 2005, respectively, and $15 million and $9 million during the nine months ended September 30, 2006 and 2005, respectively. At September 30, 2006, cumulative unrealized losses of $25 million (pre-tax) have been recognized on hedge contracts that pertain to the remainder of 2006, 2007 and 2008. See "Market Risk Exposures—Commodity Price Risk" for more information regarding forward market prices.

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. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall) which reduces generation and increases major maintenance costs which are recorded as an expense when incurred. Accordingly, earnings from the

Illinois Plants and Homer City 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 the commercial platform of 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 primarily in the eastern power grid using products available over the counter, through exchanges and from independent system operators. Earnings from energy trading activities decreased $30 million and $16 million for the third quarter of 2006 and nine months ended September 30, 2006, respectively, compared to the corresponding periods of 2005. The 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

EME's earnings from the San Juan Mesa wind project were $5 million for the nine months ended September 30, 2006, with no earnings recorded in 2005 due to the acquisition of the San Juan Mesa wind project on December 27, 2005.

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

Earnings from Unconsolidated Affiliates

Big 4 Projects

Earnings from the Big 4 projects decreased $11 million and $17 million for the third quarter of 2006 and nine months ended September 30, 2006, respectively, compared to the corresponding periods of 2005. The decreases in earnings were partially due to lower earnings from the Kern River project during the first nine months of 2006, compared to the first nine months of 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 decreases in earnings were also attributable to lower earnings from the Watson project during the third quarter of 2006 and nine months ended September 30, 2006 primarily due to lower energy margins resulting from lower natural gas prices.

The earnings from the Big 4 projects included interest expense from Edison Mission Energy Funding of $1 million and $2 million for the third quarters of 2006 and 2005, respectively, and $4 million and $7 million for the nine months ended September 30, 2006 and 2005, respectively.

March Point

EME's share of earnings from its ownership interest in March Point was $5 million for the third quarter of 2005 and $9 million for the nine months ended September 30, 2005, resulting, in part, from mark-to-market gains (losses) related to gas purchase contracts. During the third quarter of 2005, EME recorded an impairment charge related to its March Point investment which resulted in suspension of equity accounting. Accordingly, no earnings were recorded during the first nine months of 2006.

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

Losses from the Doga project increased $5 million and $6 million in the third quarter of 2006 and nine months ended September 30, 2006, respectively, compared to the corresponding periods of 2005. The increases in losses were 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 this will reduce future income tax payments, Doga reported a loss from a reduction in deferred tax assets (related to levelization of income under the power purchase agreement for financial reporting purposes).

Seasonal Disclosure

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

Corporate Interest Income

EME corporate interest income increased $8 million and $21 million for the third quarter of 2006 and nine months ended September 30, 2006, respectively, compared to the corresponding periods of 2005. The increases were primarily attributable to higher interest rates in 2006 compared to 2005.

Corporate Interest Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)			
Interest expense to third parties	$ 33	$ 39	$ 107	$ 118
Interest expense to Midwest Generation(1)	30	28	86	85
Total corporate interest expense	$ 63	$ 67	$ 193	$ 203

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

Interest Expense to Third Parties

EME's interest expense to third parties decreased $6 million and $11 million for the third quarter of 2006 and nine months ended September 30, 2006, respectively, compared to the corresponding periods of 2005. The decreases were primarily attributable to lower interest rates resulting from EME's refinancing in June 2006.

Corporate Administrative and General Expenses

Administrative and general expenses decreased $10 million for the nine months ended September 30, 2006, compared to the corresponding period of 2005. The decrease was primarily due to $10 million of costs incurred during the nine months ended September 30, 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 $143 million in the first nine months of 2006 related to the early repayment of substantially 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 the first nine months of 2005 consisting of a $4 million loss related to the early repayment of EME's junior subordinated debentures recorded during the first quarter of 2005.

Other Income (Expense), Net

Other income (expense), net increased $16 million for the nine months ended September 30, 2006, compared to the corresponding period of 2005. The 2006 increase was partially attributable to an $8 million gain related to receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter of 2006.

Income Taxes

EME's income tax provision from continuing operations was $135 million and $123 million for the nine months ended September 30, 2006 and 2005, respectively. Income tax benefits are recognized pursuant to a tax-allocation agreement with Edison International. See "Liquidity and Capital Resources—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Agreement." During the nine months ended September 30, 2006 and 2005, EME recognized $12 million and $5 million, respectively, of production tax credits related to wind projects 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.

Results of Discontinued Operations

Income (loss) from discontinued operations, net of tax, was $(2) million and $27 million for the third quarters of 2006 and 2005, respectively, and $75 million and $55 million during the first nine months of 2006 and 2005, respectively. The 2006 year-to-date increase is largely attributable to distributions received from the Lakeland project, discussed below. During the first nine months of 2005, EME completed the following sales:

- On January 10, 2005, EME sold its 50% equity interest in the 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 a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as IPM. Proceeds from the sale were approximately $20 million.

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

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. The majority 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 default by the project's counterparty, a subsidiary of TXU Europe Group plc and the project company was subsequently placed in liquidation. In response to its claim against the TXU subsidiary for damages resulting from the termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the amount of the settlement remaining after payment of creditor claims. As creditor claims have been settled, EME has received to date payments of £13 million (approximately $24 million) in April 2005, £61 million (approximately $106 million) in the first quarter of 2006, and £9 million (approximately $16 million) in April 2006. The after-tax income attributable to the Lakeland project was none for both the third quarters of 2006 and 2005 and $83 million and $24 million for the nine months ended September 30, 2006 and 2005, respectively. Beginning in 2002, EME reported the Lakeland project among discontinued operations and accounts for its ownership of Lakeland Power on the cost method, with earnings being recognized as cash is distributed from the project.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Edison Mission Energy, see "Edison Mission Energy and Subsidiaries Notes to Consolidated Financial Statements—Note 13. New Accounting Pronouncements."

LIQUIDITY AND CAPITAL RESOURCES

Introduction

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

For a complete discussion of these issues, read this quarterly report on Form 10-Q in conjunction with EME's annual report on Form 10-K for the year ended December 31, 2005.

EME's Liquidity

At September 30, 2006, EME and its subsidiaries had cash and cash equivalents and short-term investments of $1.9 billion and EME had a total of $959 million available of borrowing capacity under its $500 million corporate credit facility and the working capital facility at Midwest Generation. EME's consolidated debt at September 30, 2006 was $3.2 billion. In addition, EME's subsidiaries had $4.3 billion of long-term lease obligations related to the sale-leaseback transactions that are due over periods ranging up to 28 years.

EME Financing Developments

During June 2006, EME replaced its $98 million credit agreement with a new credit agreement that provides for a $500 million senior secured revolving loan and letter of credit facility and matures on June 15, 2012. 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 will be deposited. EME will be free to use these proceeds unless an event of default occurs under the credit facility.

Also in June 2006, EME completed a private offering of $500 million aggregate principal amount of its 7.50% senior notes due June 15, 2013 and $500 million aggregate principal amount of its 7.75% senior notes due June 15, 2016. EME will pay interest on the senior notes on June 15 and December 15 of each year, beginning on December 15, 2006. The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount of, plus accrued and unpaid interest and liquidated damages, if any, on, the senior notes plus a "make-whole" premium. On October 12, 2006, EME commenced an offer to exchange the senior notes for an equal principal amount of senior notes which have been registered under the Securities Act.

EME used the net proceeds of the offering of the senior notes, together with cash on hand, to purchase $369 million in aggregate principal amount of its 10% senior notes due August 15, 2008 and $596 million in aggregate principal amount of its 9.875% senior notes due April 15, 2011, that were validly tendered pursuant to EME's previously announced cash tender offer and consent solicitation. The net proceeds of the offering of the senior notes, together with cash on hand, were also used to pay related tender premiums, consent fees and accrued interest. EME recorded a $143 million loss on early extinguishment of debt during the second quarter of 2006. On October 26, 2006, EME notified the trustees for its 10% senior notes and 9.875% senior notes of its intent to redeem all of the remaining $35 million of senior notes outstanding pursuant to the terms of their respective indentures. EME expects to close these transactions by the end of 2006 and record an additional after-tax loss on early extinguishment of debt of approximately $2 million in the fourth quarter of 2006.

Capital Expenditures

The estimated capital and construction expenditures of EME's subsidiaries are $295 million in the final quarter of 2006 and $614 million, $31 million and $25 million for 2007, 2008 and 2009, respectively. The non-environmental portion of these expenditures relates to the construction of wind projects, purchases of turbines, upgrades to dust collection/mitigation systems and the coal handling system, ash removal improvements and various other projects. EME plans to finance these expenditures with existing subsidiary credit agreements, cash on hand or cash generated from operations. Included in the estimated expenditures are environmental expenditures of $3 million for the final quarter of 2006, $12 million for 2007, $6 million for 2008, and $25 million for 2009. The environmental expenditures relate to environmental projects such as selective catalytic reduction system improvements at the Homer City facilities and projects at the Illinois Plants. See discussion regarding possible additional capital expenditures under "Mangement's Overview; Critical Accounting Estimates—Management's Overview—Environmental Developments Regarding Emissions."

EME's Historical Consolidated Cash Flow

Consolidated Cash Flows from Operating Activities

Cash provided by operating activities from continuing operations increased $1.3 billion in the first nine months of 2006, compared to the first nine months of 2005. The 2006 increase was primarily attributable to a decrease of $500 million in required margin and collateral deposits in 2006 for EME's price risk management and trading activities, compared to an increase of $684 million in 2005. This change resulted from a decrease in forward market prices at September 30, 2006 as compared to December 31, 2005.

Cash provided by operating activities from discontinued operations increased $62 million in the first nine months of 2006, compared to the first nine months of 2005. The 2006 increase reflects higher distributions received in 2006 compared to 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

Cash used in financing activities from continuing operations decreased $371 million in the first nine months of 2006, compared to the first nine months of 2005. The 2006 decrease was primarily attributable to net proceeds of $1 billion received from EME's issuance of senior notes in June 2006, which were mostly used to repay $965 million of EME's outstanding senior notes and $136 million paid for tender premiums and related fees. In addition, dividend payments were made to MEHC of $360 million in 2005 compared to dividend payments to MEHC totaling $51 million in 2006. In 2006, Midwest Generation also had borrowings of $395 million under its credit facility, offset by repayments of $535 million. In 2005, EME repaid its junior subordinated debentures for $150 million and Midwest Generation repaid $302 million related to its existing term loan.

Consolidated Cash Flows from Investing Activities

Cash used in investing activities from continuing operations increased $612 million in the first nine months of 2006, compared to the first nine months of 2005. The 2006 increase was primarily due to net purchases of marketable securities of $184 million in the first nine months of 2006, compared to net sales of marketable securities of $140 million in the first nine months of 2005. In addition, EME paid $18 million towards the purchase price of the Wildorado wind project during the first quarter of 2006, incurred higher capital expenditures in 2006 and received lower proceeds from sales of projects. In 2005, EME received proceeds of $124 million from the sale of its 25% investment in the Tri Energy project and its 50% investment in the CBK project compared to proceeds of $43 million in 2006 from the sale of 25% of its ownership interest in the San Juan Mesa wind project.

Credit Ratings

Overview

Credit ratings for EME and its subsidiaries, Midwest Generation and EMMT, at September 30, 2006, are as follows:

	Moody's Rating	S&P Rating
EME	B1	BB-
Midwest Generation:		
First priority senior secured rating	Baa3	BB
Second priority senior secured rating	Ba2	B+
EMMT	Not Rated	BB-

On September 27, 2006, Moody's raised Midwest Generation's first priority senior secured rating to Baa3 from Ba2 and its second priority senior secured rating to Ba2 from Ba3. On September 29, 2006, Standard & Poor's raised the credit rating of EME and EMMT to BB- from B+. In addition, Standard & Poor's raised Midwest Generation's first priority senior secured rating to BB from BB- and its second priority senior secured rating to B+ from B.

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 or EME being required to make equity contributions or provide additional financial support to its subsidiaries.

Credit Rating of EMMT

The Homer City sale-leaseback documents restrict EME Homer City's ability to enter into trading activities, as defined in the documents, with EMMT to sell forward the output of the Homer City facilities if EMMT does not have an investment grade credit rating from Standard & Poor's 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, 2006. 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 price risk management 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. Because the credit ratings of EMMT and EME are below investment grade, EME has historically 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 price risk management and trading activities. At September 30, 2006, EMMT had deposited $101 million in cash with brokers in margin accounts in support of futures contracts and had deposited $97 million with counterparties in support of forward energy and transmission contracts. In addition, EME had issued letters of credit of $19 million in support of commodity contracts at September 30, 2006.

Future cash collateral requirements may be higher than the margin and collateral requirements at September 30, 2006, if wholesale energy prices increase or the amount hedged increases. EME estimates that margin and collateral requirements for energy contracts outstanding as of September 30, 2006 could increase by approximately $550 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 September 30, 2006, Midwest Generation had borrowed $30 million under this credit facility which was partially used to finance margin advances to EMMT of $62 million. In addition, EME has cash on hand and a $500 million working capital facility to provide credit support to subsidiaries. See "—EME Financing Developments" and "—EME's Liquidity as a Holding Company" for further discussion.

EME's Liquidity as a Holding Company

Overview

At September 30, 2006, EME had corporate cash and cash equivalents and short-term investments of $1.5 billion 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."

EME Homer City Interim Funding Arrangements

During March 2006, EME, through its subsidiary, Edison Mission Finance, advanced funds in the amount of $9 million to EME Homer City under the subordinated revolving loan agreement in place between Edison Mission Finance and EME Homer City. The funds were used to assist EME Homer City with a cash shortfall resulting from reduced revenues and higher maintenance expenses caused by the Unit 3 outage. For similar reasons, at the end of March 2006 and April 2006, EMMT made advance payments to EME Homer City in the amounts of $43.5 million and $20 million, respectively, against future deliveries of power to it under its trading arrangements with EME Homer City. The proceeds of the subordinated loans were deposited in EME Homer City's operating account and the prepayment by EMMT was deposited in EME Homer City's revenue account. In October 2006, EME Homer City returned the $9 million previously advanced by Edison Mission Finance. It is currently anticipated that all the advance payments by EMMT will be applied against amounts invoiced to EMMT within the next six months.

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.

	Nine Months Ended September 30,	
	2006	**2005**
	(in millions)	
Distributions from Consolidated Operating Projects:		
Edison Mission Midwest Holdings (Illinois Plants)(1)	$ 380	$ 171
EME Homer City Generation L.P. (Homer City facilities)	—	62
Holding companies of other consolidated operating projects	3	1
Distributions from Unconsolidated Operating Projects:		
Edison Mission Energy Funding Corp. (Big 4 Projects)(2)	86	93
Sunrise Power Company	7	5
Holding company for Doga project	—	17
Holding companies for Westside projects	11	13
Holding companies of other unconsolidated operating projects	1	5
Total Distributions	$ 488	$ 367

(1) Subsequent to September 30, 2006, Edison Mission Midwest Holdings made an additional distribution of $162 million.

(2) 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 received tax-allocation payments from Edison International of $159 million and $49 million during the third quarters of 2006 and 2005, respectively. EME made cumulative tax-allocation payments to Edison International of $3 million during the first nine months of 2006 (net of third quarter receipts) and received tax-allocation payments from Edison International of $52 million during the first nine months of 2005.

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 for the twelve months ended September 30, 2006:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation, LLC (Illinois Plants)	Interest Coverage Ratio	Greater than or equal to 1.40 to 1	6.09 to 1
Midwest Generation, LLC (Illinois Plants)	Secured Leverage Ratio	Less than or equal to 7.25 to 1	1.85 to 1
EME Homer City Generation L.P. (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.21 to 1(1)

(1) The senior rent service coverage ratio is determined by dividing net operating cash flow by senior rent. Net operating cash flow represents revenues less operating expenses as defined in the sale-leaseback documents. Revenue during the twelve months ended September 30, 2006 includes $43.5 million and $20 million from an advance payment from EMMT on March 31, 2006 and April 30, 2006, respectively, against future deliveries of power to it under its trading arrangements with EME Homer City.

For a more detailed description of the covenants binding EME's principal subsidiaries that may restrict the ability of those entities to make distributions to EME directly or indirectly through the other holding companies owned by EME, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Dividend Restrictions in Major Financings" of EME's annual report on Form 10-K for the year ended December 31, 2005.

Contingencies

FERC Notice Regarding Investigatory Proceeding against EMMT

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

Midway-Sunset Cogeneration Company

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

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

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

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

Off-Balance Sheet Transactions

For a discussion of EME's off-balance sheet transactions, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Off-Balance Sheet Transactions" of EME's annual report on Form 10-K for the year ended December 31, 2005. There have been no significant developments with respect to EME's off-balance sheet transactions that affect disclosures presented in EME's annual report.

Environmental Matters and Regulations

For a discussion of EME's environmental matters, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations" of EME's annual report on Form 10-K for the year ended December 31, 2005 and the notes to the Consolidated Financial Statements set forth therein. There have been no significant developments with respect to environmental matters specifically affecting EME since the filing of EME's annual report, except as follows:

Federal—United States of America

Clean Air Act

Mercury Regulation—

As part of its evaluation of environmental control technologies for the Homer City facilities, EME has considered installing flue gas desulfurization systems for Units 1 and 2 (similar to Unit 3 which has this technology) to reduce emissions, including mercury. However, in light of higher estimated capital costs, the impact of the recent decline in emissions costs, the ongoing development of more cost-effective, alternative mercury control technologies and the continued uncertainty over the final provisions of relevant environmental regulations, EME has deferred making commitments for the installation of further environmental controls at the Homer City facilities at this time. EME is studying alternative environmental technologies while continuing to review and refine the scope of the project, estimated costs for control equipment and to monitor developments related to mercury and other environmental regulations.

National Ambient Air Quality Standards—

On September 22, 2006 the US Environmental Protection Agency signed a final rule that implements the revisions to its fine particulate standard originally proposed on January 17, 2006. Under the new rule, the annual standard remains the same but the 24-hour fine particulate standard is significantly more stringent. The rule may require states to impose further emission reductions beyond those necessary to meet the existing standards. EME anticipates that any such further emissions reduction obligations would not be imposed under this standard until 2010 at the earliest, and intends to consider such rules as part of its overall plan for environmental compliance.

State—Illinois

Air Quality

On March 14, 2006, the Illinois Environmental Protection Agency submitted a proposed rule for reduction of mercury emissions to the Illinois Pollution Control Board, or PCB, for adoption. The proposed mercury 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 twelve-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 Clean Air Mercury Rule cap and trade program would be prohibited. The first hearing on the proposed mercury rule was held in June 2006 and a second hearing was held in August 2006.

In July 2006, Ameren Corporation, and in August 2006, Dynegy Inc., announced agreements with the Illinois Environmental Protection Agency to reduce mercury, NOx, SO2 and fine particulates at their Illinois coal-fired power plants. These agreements, called the Multi-Pollutant Standards or MPS, were introduced in the mercury rulemaking proceeding as a part of the mercury rule. The MPS is intended to be available to any owner of an Illinois coal-fired generator, provided that the owner makes an election by December 31, 2007, to participate in the MPS. The election must identify the generators subject to the MPS (the MPS Group), as well as the generators to be permanently shut down.

The MPS requires each generator in the MPS Group to install and operate certain mercury control technology by July 2009. If the mercury control equipment is installed and operated properly, the generators in the MPS Group are exempted, until December 31, 2014, from the 90% emissions reduction requirement of the proposed mercury rule. Generators in the MPS Group must, however, meet certain NOx and SO2 emissions reductions by 2012 and 2013, respectively, and are required to forfeit emissions allowances to the state. Allowances from units identified for permanent shutdown in the December 31, 2007, election are not forfeited if the units are retired by December 31, 2010. Companies that do not elect to participate in the MPS rule will be subject to the pending mercury rule, but do not have to meet the SO2 and NOx targets of the MPS rule and do not have to forfeit emissions allowances. These companies will be subject to the SO2 and NOx targets which will become part of the Illinois SIPs implementing federal CAIR and the 8-hour ozone and fine particulate standards described below.

Final comments on the mercury rule and the MPS were filed on September 20, 2006. On November 2, 2006, the PCB adopted the rule as proposed, with the addition of the MPS provisions. The rule now must be submitted to the General Assembly's Joint Committee on Administrative Rules for adoption, objection or prohibition. If adopted by the Joint Committee, the rule becomes effective after publication in the Illinois register. Rules adopted through such state proceedings are also subject to court appeal.

On May 30, 2006, the Illinois EPA submitted a proposed regulation to the Illinois PCB to implement the Illinois SIP required for compliance with the federal Clean Air Interstate Rule which requires reductions in NOx and SO2. The Illinois PCB has held a hearing on this SIP on October 10, 2006 and has scheduled another hearing for November 28, 2006. Although this SIP was to be submitted to the US EPA by September 11, 2006, the US EPA federal implementation plan which was promulgated on March 15, 2006 allows the Illinois EPA to submit an abbreviated SIP by March 31, 2007. The Illinois EPA has also begun to develop SIPs to meet National Ambient Air Quality Standards for 8-hour ozone and fine particulates. These SIPs will be developed with the intent of bringing non-attainment areas, such as Chicago, into attainment. They are expected to deal with all emission sources, not just power generators, and to address emissions of NOx, SO2, and volatile organic compounds. These SIPs are to be submitted to the US EPA by June 15, 2007 for 8-hour ozone, and by April 5, 2008 for fine particulates.

While the final forms of the mercury rule, the MPS, and the SIPs are not currently known, the costs to add appropriate environmental equipment, which could include flue gas desulfurization systems, selective catalytic reduction systems, bag-houses, sorbent injection systems, or other environmental equipment, could be significant.

State—Pennsylvania

Air Quality

With respect to mercury, on May 17, 2006, the Pennsylvania Department of Environmental Protection submitted a proposed rule to the State's Environmental Quality Board that would require coal-fired power plants to reduce mercury emissions by 80% by 2010 and 90% by 2015. The proposed rule would not allow the use of emissions trading to achieve compliance. The rule was adopted by the Environmental Quality Board on October 17, 2006, but remains subject to another round of review and comment by the Independent Regulatory Review Commission and committees of the General Assembly before it can take effect. The General Assembly also is considering adoption of mercury regulations that could pre-empt the Environmental Quality Board rulemaking. In May 2006, the State Senate passed a bill that would implement the federal Clean Air Mercury Rule as the state rule. The House has held several committee hearings on the Senate bill for potential alternatives. While the final form of the SIPs is not currently known, if the mercury regulation as adopted by the Environmental Quality Board becomes the state's final rule, EME expects the Homer City facilities to achieve compliance by the 2010 deadline with mercury removal achieved by an existing flue gas desulfurization system on one generating unit and by sorbent injection on the other two units.

Climate Change

In September 2006, California's Governor Schwarzenegger signed two bills into law regarding greenhouse gas emissions. The first, known as AB 32 or the California Global Warming Solutions Act of 2006, establishes a comprehensive program of regulatory and market mechanisms to achieve reductions of greenhouse gases. AB 32 requires the California Air Resources Board to develop regulations and market mechanisms targeted to reduce California's greenhouse gas emissions to 1990 levels by 2020. Mandatory caps will begin in 2012 and will be reduced incrementally each year so that emissions of greenhouse gases will be reduced to the 1990 levels by 2020. The second bill, known as SB 1368, requires the California Energy Commission to develop and adopt by regulation a greenhouse gas emissions performance standard for long-term procurement of electricity by local publicly owned utilities equal to that of a combined-cycle gas turbine generator. The California Energy Commission must adopt the standard on or before June 30, 2007, and it must be consistent with the standard to be adopted by the California Public Utilities Commission for load-serving entities under its jurisdiction on or before February 1, 2007. In addition, the California Public Utilities Commission is addressing climate change related issues in various regulatory proceedings. At this time, EME believes that all of its facilities in California meet the greenhouse gas emissions performance standard contemplated by SB 1368, but EME will continue to monitor both regulations, as they are developed, for potential impact on its existing facilities and its projects under development.

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:

For a complete discussion of these issues, read this quarterly report on Form 10-Q in conjunction with EME's annual report on Form 10-K for the year ended December 31, 2005.

Commodity Price Risk

General Overview

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

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

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

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

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

Introduction

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

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

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

Hedging Strategy

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

• the use of contracts cleared on the Intercontinental Trading Exchange and the New York Mercantile Exchange,

• forward sales transactions entered into on a bilateral basis with third parties, including electric utilities and power marketing companies, and

• 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.

EMMT participated in an Illinois auction in September 2006, which resulted in its entry into two load requirements contracts with Commonwealth Edison with periods of seventeen months and twenty-nine months, beginning January 1, 2007. Under these load requirements services contracts, the amount of power sold is a portion of the retail load of the purchasing utility and 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.

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 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, negotiated by EMMT with customers through a combination of bilateral agreements, 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. However, hedging transactions which settle at points other than the Northern Illinois Hub are subject to the possibility of basis risk. See "—Basis Risk" below for further discussion.

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

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

	24-Hour Northern Illinois Hub Historical Energy Prices(1)	
	2006	**2005**
January	$ 42.27	$ 38.36
February	42.66	34.92
March	42.50	45.75
April	43.16	38.98
May	39.96	33.60
June	34.80	42.45
July	51.82	50.87
August	54.76	60.09
September	31.87	53.30
Nine-Month Average	$ 42.64	$ 44.26

(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 market prices for energy per megawatt-hour as quoted for sales into the Northern Illinois Hub at September 30, 2006:

	24-Hour Northern Illinois Hub Forward Energy Prices(1)
2006	
October	$ 28.52
November	33.26
December	40.57
2007 Calendar "strip"(2)	$ 44.31
2008 Calendar "strip"(2)	$ 45.09

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

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

The following table summarizes Midwest Generation's hedge position at September 30, 2006:

	2006	2007	2008	2009
Energy Only Contracts(1)				
Megawatt-hours	5,135,440	16,645,200	10,649,600	2,048,000
Average price/MWh(2)	$ 45.56	$ 48.37	$ 61.32	$ 60.00
Load Requirements Services Contracts				
Estimated megawatt-hours(3)		8,521,953	6,208,878	1,805,187
Average price/MWh(4)		$ 63.98	$ 63.99	$ 64.00
Total estimated megawatt-hours	5,135,440	25,167,153	16,858,478	3,853,187

(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 September 30, 2006 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 megawatt-hours 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 megawatt-hour 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 megawatt-hour under a load requirements services contract is not comparable to the sale of power under an energy only contract. The average price per megawatt-hour under a load requirements services contract represents the sale of the bundled product based on an estimated customer load profile.

The load requirements services contracts set forth in the table above are with Commonwealth Edison. Commonwealth Edison has stated that it would face possible bankruptcy if an electric rate freeze, scheduled to expire January 1, 2007, was extended through legislation as proposed by a committee of the Illinois House of Representatives on October 10, 2006. EME is unable to predict whether this legislative effort will result in an extension of the rate freeze and, if this occurs, what affect it may have on Commonwealth Edison's performance under the load requirement services contracts.

Energy Price Risk Affecting Sales from the Homer City Facilities

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 during the first nine months of 2006 and 2005:

	Historical Energy Prices(1) 24-Hour PJM			
	Homer City		West Hub	
	2006	2005	2006	2005
January	$ 48.67	$ 45.82	$ 54.57	$ 49.53
February	49.54	39.40	56.39	42.05
March	53.26	47.42	58.30	49.97
April	48.50	44.27	49.92	44.55
May	44.71	43.67	48.55	43.64
June	38.78	46.63	45.78	53.72
July	53.68	54.63	63.47	66.34
August	58.60	66.39	76.57	82.83
September	33.26	66.67	34.40	76.82
Nine-Month Average	$ 47.67	$ 50.54	$ 54.22	$ 56.61

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

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

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the PJM West Hub at September 30, 2006:

	24-Hour PJM West Hub Forward Energy Prices(1)
2006	
October	$ 34.15
November	42.29
December	54.08
2007 Calendar "strip"(2)	$ 57.61
2008 Calendar "strip"(2)	$ 58.25

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

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

The following table summarizes Homer City's hedge position at September 30, 2006:

	2006	2007	2008
Megawatt-hours	2,199,100	7,590,000	6,763,200
Average price/MWh(1)	$ 53.47	$ 64.35	$ 61.86

(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 September 30, 2006 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

The average price/MWh for 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.

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 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 price risk management activities use these settlement points (and, to a lesser extent, other similar trading hubs) to enter into hedging contracts. EME's revenues with respect to such forward contracts include:

- sales of actual generation in the amounts covered by the forward contracts with reference to PJM spot prices at the busbar of the plant involved, plus,
- sales to third parties at the price under such hedging contracts at designated settlement points (generally the PJM West Hub for the Homer City facilities and the Northern Illinois Hub for the Illinois Plants) less the cost of power at spot prices at the same designated settlement points.

Under PJM's market design, locational marginal pricing, which establishes market prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, can cause the price of a specific delivery point to be higher or lower relative to other locations depending on how the point is affected by transmission constraints. To the extent that, on the settlement date of a hedge contract, spot prices at the relevant busbar are lower than spot prices at the settlement point, the proceeds actually realized from the related hedge contract are effectively reduced by the difference. This is referred to as "basis risk." During the nine months ended September 30, 2006, transmission congestion in PJM has resulted in prices at the Homer City busbar being lower than those at the PJM West Hub (EME Homer City's primary trading hub) by an average of 12%, compared to 11% during the nine months ended September 30, 2005. The monthly average difference during the twelve months ended September 30, 2006 ranged from 3% to 23%. In contrast to the Homer City facilities, during the past 12 months, the prices at the Northern Illinois Hub were substantially the same as those at the individual busbars of the Illinois Plants.

By entering into cash settled futures contracts and forward contracts using the PJM West Hub and the Northern Illinois Hub (or other similar trading hubs) as settlement points, EME is exposed to basis risk as described above. In order to mitigate basis risk, EME has purchased 5.6 terawatt-hours of financial transmission rights and basis swaps in PJM for Homer City during the period October 1, 2006 through May 31, 2007, and may continue to purchase financial transmission rights and basis swaps in the future. 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 price risk management activities include using financial transmission rights alone or in combination with forward contracts and basis swap contracts to manage basis risk.

Coal Price and Transportation Risk

The Illinois Plants and the Homer City facilities purchase coal primarily obtained from the Southern Powder River Basin 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 contracts at September 30, 2006 for the remainder of 2006 and the following four years.

	Amount of Coal Under Contracts in Millions of Tons(1)				
	October through December 2006	2007	2008	2009	2010
Illinois Plants	3.9	16.6	5.8	5.8	5.8
Homer City facilities	1.2	5.1	2.1	0.8	—

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

EME is subject to price risk for purchases of coal that are not under contract. Prices of Northern Appalachian (NAPP) coal, which are related to the price of coal purchased for the Homer City facilities, increased considerably during 2005. The price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO2 per MMBtu sulfur content) fluctuated between $44 per ton and $57 per ton during 2005, with a price of $45 per ton at December 30, 2005, as reported by the Energy Information Administration. The 2005 overall increase in the NAPP coal price was largely attributed to greater demand from domestic power producers and increased international shipments of coal to Asia. During the first nine months of 2006, the price of NAPP coal decreased to $38.75 per ton at September 29, 2006, as reported by the Energy Information Administration, due to the combined effects of mild weather, easing natural gas prices and improving eastern stockpiles. Prices of Powder River Basin (PRB) coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO2 per MMBtu sulfur content), which is purchased for the Illinois Plants, significantly increased in 2005 due to the curtailment of coal shipments during 2005 due to increased PRB coal demand from other regions (east), rail constraints (discussed below), higher oil and natural gas prices and higher prices for SO2 allowances. On September 29, 2006, the Energy Information Administration reported the price of PRB coal to be $9.45 per ton, which compares to 2005 prices that ranged from $6.20 per ton to $18.48 per ton. The price of PRB coal decreased during the first nine months of 2006 from 2005 year-end prices due to easing natural gas prices, fuel switching, lower prices for SO2 allowances and improved inventory.

After two derailments in May 2005, the railroads that bring coal from the PRB mines to the Illinois Plants discovered significant problems with the joint-rail line that serves the PRB mines. Repairs to the joint-rail line are expected to continue through most of 2006. Even though some restrictions in coal shipments have occurred while repairs are being completed, EME expects to continue receiving a sufficient amount of coal to generate power based on communications with the railroad companies.

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO2 allowances, and Illinois and Pennsylvania regulations implemented the federal NOx SIP Call requirement. Under these programs, 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. 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.

The price of emission allowances, particularly SO2 allowances issued through the federal Acid Rain Program, decreased during the first nine months of 2006 from 2005 year-end prices. The average price of purchased SO2 allowances decreased to $899 per ton during the nine months ended September 30, 2006 from $1,219 per ton during 2005. The decrease in the price of SO2 allowances during the nine months ended September 30, 2006 from 2005 year-end prices has been attributed to a decline in natural gas prices and fuel switching from oil to gas. The price of SO2 allowances, determined by obtaining broker quotes and information from other public sources, was $538 per ton as of October 31, 2006.

For a discussion of environmental regulations related to emissions, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Environmental Matters and Regulations" of EME's annual report on Form 10-K for the year ended December 31, 2005.

Credit Risk

In conducting EME's price risk management 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.

EME measures credit risk exposure from counterparties of its merchant energy activities 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 price risk management 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 September 30, 2006, the amount of exposure, broken down by the credit ratings of EME's counterparties, was as follows:

S&P Credit Rating	September 30, 2006 (in millions)
A or higher	$ 93
A-	38
BBB+	79
BBB	32
BBB-	163
Below investment grade	2
Total	$ 407

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 62% of EME's consolidated operating revenues for the nine months ended September 30, 2006. Moody's Investors Service rates PJM's senior unsecured debt Aa3. PJM, an independent system operator with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At September 30, 2006, EME's account receivable due from PJM was $73 million. For the nine months ended September 30, 2006, a second customer accounted for 10% of EME's consolidated operating revenues.

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 $3.5 billion at September 30, 2006, compared to the carrying value of $3.2 billion.

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):

	September 30, 2006	December 31, 2005
Commodity price:		
Electricity	$ 162	$ (434)

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The following table summarizes the maturities and the related fair value, based on actively traded prices, of EME's commodity price risk management assets and liabilities as of September 30, 2006 (in millions):

	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 162	$ 88	$ 74	$ —	$ —

Energy Trading Derivative Financial Instruments

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

	September 30, 2006		December 31, 2005	
	Assets	Liabilities	Assets	Liabilities
Electricity	$ 106	$ —	$ 127	$ 27
Other	2	—	1	—
Total	$ 108	$ —	$ 128	$ 27

The change in the fair value of trading contracts for the nine months ended September 30, 2006, was as follows (in millions):

Fair value of trading contracts at January 1, 2006	$ 101
Net gains from energy trading activities	115
Amount realized from energy trading activities	(106)
Other changes in fair value	(2)
Fair value of trading contracts at September 30, 2006	$ 108

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 September 30, 2006) (in millions):

	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 21	$ 18	$ 3	$ —	$ —
Prices based on models and other valuation methods . . .	87	3	12	18	54
Total	$ 108	$ 21	$ 15	$ 18	$ 54

Regulatory Matters

For a discussion of EME's regulatory matters, refer to "Item 1. Business—Regulatory Matters" of EME's annual report on Form 10-K for the year ended December 31, 2005. There have been no significant developments with respect to regulatory matters specifically affecting EME since the filing of EME's annual report on Form 10-K for the year ended December 31, 2005, except as follows:

PJM Reliability Pricing Model

On August 31, 2005, PJM filed under sections 205 and 206 of the Federal Power Act a proposal for a reliability pricing model, or RPM, to replace its existing capacity construct. The proposal offers RPM as a new capacity construct to address the deficiencies in PJM's current structure in a comprehensive and integrated manner. On April 20, 2006, the FERC issued an Initial Order on RPM, finding that as a result of a combination of factors, PJM's existing capacity construct is unjust and unreasonable as a long-term capacity solution, because it fails to set prices adequate to ensure energy resources to meet its reliability responsibilities. Although the FERC did not find that the RPM proposal, as filed by PJM, is a just and reasonable replacement for the current capacity construct because some elements of the proposal need further development and elaboration, it did find that certain elements of the RPM proposal, with some adjustment and clarification, may form the basis for a just and reasonable capacity market. Accordingly, in the order the FERC provided guidance on PJM's RPM proposal, as well as other features that need to be included in a just and reasonable capacity market, and established further proceedings to resolve these issues. On September 29, 2006, a comprehensive settlement agreement among PJM and many of its stakeholders, including EME, proposing a capacity market construct in PJM was submitted to FERC for approval. At this time, EME believes that there is substantial support for the settlement proposal, and that the implementation of the settlement would benefit the Illinois Plants and the Homer City facilities.

MISO Revenue Sufficiency Guarantee Charges

On April 25, 2006, the FERC issued an order regarding the MISO's "Revenue Sufficiency Guarantee" charges, or RSG charges. The MISO's business practice manuals and other instructions to market participants have stated, since the implementation of market operations on April 1, 2005, that RSG charges will not be imposed on offers to supply power not supported by actual generation (also known as virtual supply offers). However, some market participants raised questions about the language of the MISO's tariff concerning that issue and in October 2005, the MISO submitted to the FERC proposed tariff revisions clarifying its tariff to reflect its business practices with respect to RSG charges, and filed corrected tariff sheets exempting virtual supply from RSG charges. In an April 25 decision, the FERC interpreted the MISO's tariff to require that virtual supply offers must be included in the calculation of the RSG charges and that to the extent that the MISO did not charge virtual supply offers for RSG charges, it violated the terms of its tariff. The FERC order then proceeded to require the MISO to recalculate the RSG charges back to April 1, 2005, and to make refunds to customers, with interest, reflecting the recalculated charges. As a result of that order, it was possible that the MISO would attempt to impose retroactively RSG charges on those who submitted virtual supply offers during the recalculation period. EMMT made virtual supply offers in the MISO during this period on which no RSG charges were imposed, and thus had potential exposure to such a claim for refunds from the MISO. EMMT and other parties requested rehearing of the April 25th order. On May 17, 2006, FERC issued a notice extending the time for the MISO to comply with the requirements of the April 25th order, including the requirement to refund to customers any amounts due, until after the date of issuance of an order on rehearing. On October 26, 2006, FERC issued an Order on Rehearing, declining to impose refunds. Consequently, EMMT is not required to make refunds to account for the imposition of RSG charges back to April 1, 2005.

FERC Order Regarding PJM Marginal Losses

On May 1, 2006, the FERC issued an order in response to a complaint filed by Pepco Holdings, Inc. against PJM regarding marginal losses for transmission. The FERC concluded that PJM has violated its tariff by not implementing marginal losses and further directed PJM to implement marginal losses by October 2, 2006. Implementation of marginal losses will adjust the algorithm that calculates locational marginal prices to include a marginal loss component in addition to the already included congestion component. This may reduce market prices for sellers in the Western PJM and Northern Illinois regions. On June 19, 2006, the FERC issued an order delaying implementation of marginal losses in PJM until June 1, 2007.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For a discussion of market risk sensitive instruments, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Market Risk Exposures" of EME's annual report on Form 10-K for the year ended December 31, 2005. Refer to "Market Risk Exposures" in Item 2 of this quarterly report on Form 10-Q for an update to that disclosure.

ITEM 4. 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.

Internal Control Over Financial Reporting

There were no changes in EME's internal control over financial reporting (as such term is defined in Rules 13a-15(f) or 15d-15(f) under the Exchange Act) during the quarter to which this report relates that have materially affected, or are reasonably likely to materially affect, EME's internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

FERC Notice Regarding Investigatory Proceeding against EMMT

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

ITEM 1A. RISK FACTORS

For a discussion of the risks, uncertainties, and other important factors which could materially affect EME's business, financial condition, or future results, refer to "Item 1A. Risk Factors" of EME's annual report on Form 10-K for the year ended December 31, 2005. The risks described in EME's annual report on Form 10-K are not the only risks facing EME. Additional risks and uncertainties that are not currently known, or that are currently deemed to be immaterial, also may materially adversely affect EME's business, financial condition or future results.

ITEM 6. EXHIBITS

Exhibit No.	Description
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.

SIGNATURES

Pursuant to the requirements 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

By: /s/ W. JAMES SCILACCI

W. James Scilacci
Senior Vice President and
Chief Financial Officer

Date: November 3, 2006